

5.2 AIR QUALITY

This section addresses the air quality impacts of construction and operations of the Palomar Energy Project. It covers both the power plant and the project's linear facilities. The air assessment covers the specific air quality information required by the CEC guidelines, including:

- Baseline climatological and air quality data to describe existing conditions in the project area,
- Information on criteria air pollutant sources, fuel(s) used, and operations to allow quantification of pollutant emissions and impacts on ambient air quality during project construction and operation,
- Emissions of air toxic compounds and their impact on public health (addressed in Section 5.15, Public Health),
- Mitigation of potential impacts through emission offsets and use of pollution control technologies, and
- Information required by the San Diego Air Pollution Control District (SDAPCD) in order to make their Determination of Compliance for the project.

5.2.1 Affected Environment

The existing air quality in the vicinity of the Palomar site is presented in this section. This air assessment covers the baseline climatological and air quality data to describe existing conditions in the project area, as required by the SDAPCD Rule 20.3.

5.2.1.1 Climatology

The project site is located in northern San Diego County, approximately 12 miles inland from the Pacific Ocean. Climatological data representative of the project area are available from the Miramar Naval Air Station (NAS), located approximately 15 miles south of Escondido.

Wind speed and direction influence the dispersion and transport of pollutants. Wind flows are predominantly westerly. The average wind direction during the months of February through October is from the west-northwest. During November through January, the average wind flow is from the northeast. Wind speeds over the project region average from five to eight miles per hour. Based on data from the National Climatic Data Center (NCDC, 1993), the maximum wind gusts occur in winter and have speeds of approximately 45 miles per hour.

5.2.1.2 Meteorological Data

Meteorological data for the project region have been obtained from Miramar NAS and the SDAPCD monitoring site at Escondido. The Escondido monitoring station is located within

5.2 Air Quality

the City of Escondido, approximately three miles east of the project location. Both stations were operated in accordance with EPA guidelines.

Hourly meteorological surface data from the Escondido monitoring station were used to represent transport and dispersion conditions. Gaps in the Escondido wind speed and wind direction data were supplemented with data from the Miramar monitoring station. A wind rose was prepared from the three years (1998-2000) of meteorological data used for the modeling analysis and is presented in Figure 5.2-1.

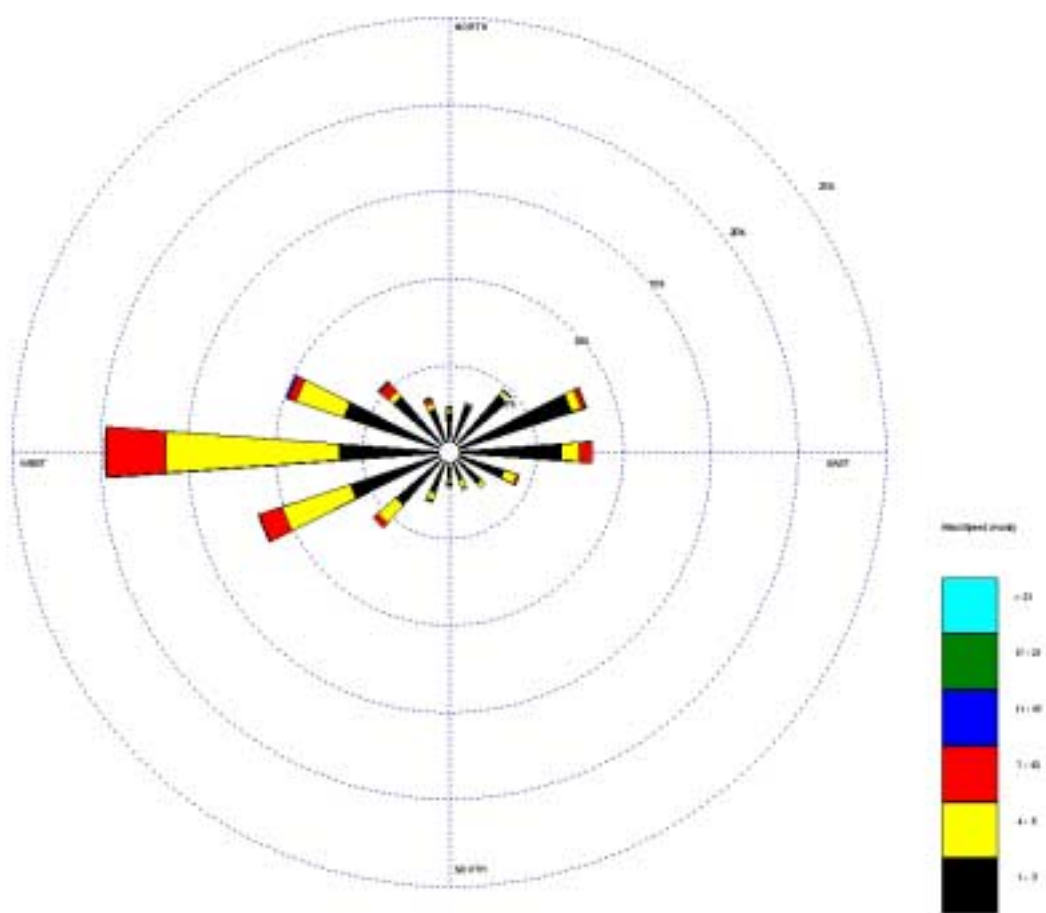


Figure 5.2-1 Escondido Windrose, January – December, 1998 – 2000

5.2.1.3 Air Quality Data

National and California ambient air quality standards are summarized in Table 5.2-1.

Table 5.2-1 National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards ^{1,3}	National Standards ²	
			Primary ⁴	Secondary ⁵
Ozone ⁶	1-hour	0.09 ppm (180 µg/m ³)	0.12 ppm (235 µg/m ³)	0.12 ppm (235 µg/m ³)
	8-hour	None	0.08 ppm (157 µg/m ³)	0.08 ppm (157 µg/m ³)
PM ₁₀	24-hour	50 µg/m ³	150 µg/m ³	150 µg/m ³
	Annual	30 µg/m ³	50 µg/m ³	50 µg/m ³
PM _{2.5}	24-hour	None	65 µg/m ³	65 µg/m ³
	Annual		15 µg/m ³	15 µg/m ³
CO	1-hour	20 ppm (23 mg/m ³)	35 ppm (40 mg/m ³)	35 ppm (40 mg/m ³)
	8-hour	9 ppm (10 mg/m ³)	9 ppm (10 mg/m ³)	9 ppm (10 mg/m ³)
NO ₂	1-hour	0.25 ppm (470 µg/m ³)	None	None
	Annual Average	None	0.053 ppm (100 µg/m ³)	0.053 ppm (100 µg/m ³)
SO ₂	1-hour	0.25 ppm (655 µg/m ³)	None	None
	3-hour	None	None	1,300 µg/m ³ (0.5 ppm)
	24-hour	0.04 ppm ⁷ (105 µg/m ³)	365 µg/m ³ (0.14 ppm)	None
	Annual Average	None	80 µg/m ³ (0.03 ppm)	None

5.2 Air Quality

Table 5.2-1 National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards ^{1,3}	National Standards ²	
			Primary ⁴	Secondary ⁵
1	California standards for O ₃ , CO, SO ₂ (1 and 24 hour), NO ₂ , and PM ₁₀ are values that are not to be exceeded. All others are not to be equaled or exceeded. California AAQS are listed in the Table of Standards in Section 70200 of Title 17 of the CCR.			
2	National standards (other than ozone and those based on annual averages or annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest eight-hour concentration in a year, averaged over three years, is equal to or less than the standard. For PM ₁₀ , the 24-hour standard is attained when 99 percent of the daily concentrations, averaged over three years, is equal to or less than the standard. For PM ₁₀ , the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard. For PM _{2.5} , the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard.			
3	Equivalent units given in parentheses are based on a reference temperature of 25 C and a reference pressure of 760 mm of mercury. Most measurements of air quality are to be corrected to a reference temperature of 25° C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to parts per million by volume, or micromoles of pollutant per mole of gas.			
4	National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.			
5	National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.			
6	New federal 8-hour ozone and fine particulate matter standards were promulgated by EPA on July 18, 1997. The federal 1-hour ozone standard continues to apply in areas that violated the standard.			
7	Standard applies at locations where the state standards for ozone and/or suspended particulate matter are violated. National standards apply elsewhere.			

Ambient air quality data is summarized for the Escondido monitoring station, which lies approximately three miles from the project site. The ambient air quality data from the Escondido station is summarized in Table 5.2-2. Levels of SO₂ are only measured in the southern part of the County and not recorded at the Escondido station. However, SO₂ concentrations elsewhere are well below the ambient air quality standards, and are expected to be very low in the project vicinity.

The monitoring data show compliance with the state and federal ambient air quality standards for SO₂, CO and NO₂. This is consistent with the federal and state attainment designations for San Diego County.

According to these data, the federal 1-hour ozone standard was not exceeded at the Escondido monitoring station during the past three years. The state ozone standard was exceeded in each of those years. San Diego County is classified as both a federal and state non-attainment area for ozone.

The data show no violations of the federal or state annual average standards for PM₁₀. There also were no violations of the federal 24-hour standard. However, the data from the Escondido monitoring station shows that the state 24-hour PM₁₀ standard was exceeded in

each of the three years reviewed. San Diego County is classified as a state (but not federal) PM₁₀ non-attainment area.

Table 5.2-2 Escondido Monitoring Station Maximum Observed Concentrations

Pollutant	Averaging Time	Units ¹	California Standards	National Standards	1998	1999	2000
Ozone	1-Hour	ppm	0.09	0.12	0.12	0.10	0.12
		(µg/m ³)	(180)	(235)	(235)	(196)	(235)
PM ₁₀	24-Hour	µg/m ³	50	150	51.0	52.0	65.0
	Annual Arithmetic Mean	µg/m ³	None	50	20.5	30.0	29.6
	Annual Geometric Mean	µg/m ³	30	None	20.8	28.5	28.0
CO	1-Hour	ppm	20	35	10.2	9.9	9.3
		(mg/m ³)	(23)	(40)	(11.9)	(11.5)	(10.8)
	8-Hour	ppm	9	9	4.6	5.3	4.9
NO ₂	1-Hour	ppm	0.25	None	0.09	0.10	0.08
		(µg/m ³)	(470)	-	(172)	(191)	(153)
	Annual Average	ppm	None	0.053	0.018	0.023	0.021
		(µg/m ³)	-	(100)	(34)	(43)	(40)

¹ Concentrations given in the units reported and in parentheses when converted to different units.

In 1997, EPA promulgated a new 8-hour ozone and 24-hour and annual PM_{2.5} AAQS. These standards were stayed pending resolution of a lawsuit filed regarding these standards. These standards were recently reinstated, but details regarding their implementation are being reassessed by EPA in response to a Federal court order.

5.2.2 Emissions Control Technology Assessment

In accordance with SDAPCD Rule 20.3(d)(1), new emission units with the potential to emit 10 pounds per day or more of NO_x, VOC, PM₁₀, or SO_x must be equipped with Best Available Control Technology (BACT). Additionally, if the project's potential CO emission increase is equal to 100 tons per year or more, BACT must be installed on each emission unit. Lowest Achievable Emission Rate (LAER) is required for federal non-attainment pollutants and their precursors, if the project's potential emissions increase constitutes a new major source. Because the region is non-attainment for ozone, LAER is required for each emission unit if the project's potential emissions of ozone precursors (NO_x and VOC) are 50 tons per year or more. By definition, LAER is at least as stringent as BACT, but can be more stringent.

5.2 Air Quality

Determination of both BACT and LAER emission levels includes evaluation of the most modern emission controls achievable, but BACT allows for consideration of economic impacts while LAER does not. Table 5.2-3 summarizes SDAPCD BACT and LAER thresholds.

Table 5.2-3 SDAPCD BACT and LAER Thresholds

Pollutant	BACT	LAER
NO _x	10 lb/day ¹	50 tpy ²
CO	100 tpy ²	Not applicable
PM ₁₀	10 lb/day ¹	Not applicable
VOC	10 lb/day ¹	50 tpy ²
SO _x	10 lb/day ¹	Not applicable

- 1 BACT is required for individual emission units with potential emissions at or above the threshold.
- 2 BACT/LAER is required for each emission unit if potential project emissions are at or above the threshold.

Potential emissions (see Table 5.2-11) from the Palomar project will exceed 50 tons per year of NO_x, which will require that LAER be used to control NO_x emissions from the gas turbines and duct burners. VOC, SO_x, and PM₁₀ emissions from each gas turbine/duct burner set are anticipated to exceed the 10 pounds per day trigger level for BACT. Potential emissions from the project will exceed 100 tons per year of CO, which will require that BACT be used to control emissions from the gas turbines and duct burners. Small quantities of PM₁₀ also will be emitted from the project's cooling towers.

5.2.2.1 "Top-Down" BACT/LAER Methodology

In accordance with federal requirements, the SDAPCD has primary authority to make BACT and LAER determinations. SDAPCD requires that the applicant submit a demonstration that their proposed control technologies and/or work practices meet the criteria for BACT/LAER. The approach used to determine BACT and LAER is commonly referred to as a "Top-Down" analysis. The "Top-Down" approach requires that all potential emission controls or combination of controls be identified for each pollutant, and that they be ranked by order of control effectiveness. In addition to add-on control technologies, controls may include process modifications, changes in raw materials or fuels, and substitution of equipment or processes.

In a "Top-Down" analysis, the top (most effective) technology must be evaluated according to the following criteria:

- Feasibility – Has the technology or work practice been "achieved in practice" at an operating facility that is functionally similar to the proposed source? EPA guidance

indicates that “achieved in practice” means that the controls have been used at a full-scale operating facility as opposed to pilot or bench-scale studies.

- Economics (BACT determinations only) – Are the capital and operating costs excessive? These costs are evaluated based on a dollar-per-ton-removed basis.
- Energy – Does the technology or work practice result in an excessive expenditure of energy or energy resources?
- Environmental – Does the work practice or technology result in significant adverse environmental impacts?

If a particular emission control is rejected based on the above criteria, the next most effective emission control on the list is evaluated until a specific control is selected as BACT or LAER.

In selecting potential candidates for BACT and LAER for the Palomar project, potentially feasible alternatives were obtained from the following sources:

- EPA’s BACT/LAER Clearinghouse and updates,
- California Air Resources Board's (ARB) BACT Clearinghouse database,
- SDAPCD BACT Guideline Document,
- Discussions with permitting staff from EPA Region IX,
- Recent CEC Applications for Certification, and
- Information from emission control vendors.

5.2.2.2 Assessment of NO_x Control Technologies

Oxides of Nitrogen Formation and Control

During combustion, NO_x is formed from two sources: fuel NO_x and thermal NO_x. NO_x formed through the oxidation of fuel-bound nitrogen is called fuel NO_x. NO_x formed through the oxidation of a portion of the nitrogen contained in the combustion air is called thermal NO_x. With natural gas combustion, most NO_x is generated through thermal NO_x. The rate of formation of thermal NO_x is a function of the residence time, free oxygen (O₂), and maximum flame temperatures in the combustion zone.

NO_x control methods can be divided into two categories: 1) combustion zone NO_x formation control, and 2) post-combustion zone NO_x formation control. In gas turbines, combustion zone NO_x formation can be limited by lowering combustion temperatures and by staging combustion (i.e., a reducing atmosphere followed by an oxidation atmosphere). NO_x formed by the combustion process can be further reduced by the use of post-combustion zone

technology, such as catalysts that typically promote the reaction of nitric oxide (NO) and nitrogen dioxide (NO₂) to elemental nitrogen (N₂) and water (H₂O).

NO_x Control Technology Assessment

The following NO_x control technologies were evaluated to determine if they are technically feasible and if they have been "achieved in practice":

- SCONO_xTM
- Dry Low NO_x (DLN) and Selective Catalytic Reduction (SCR)
- Catalytica XONONTM
- Water/Steam Injection and SCR

1. SCONO_xTM

SCONO_xTM is a NO_x reduction technology licensed by Goal Line to Alstom for gas turbine applications. This system uses a coated catalyst to control both NO_x and CO emissions without the use of a chemical reagent. The system utilizes hydrogen (H₂) and carbon dioxide (CO₂) as the basis for a proprietary catalyst regeneration process.

The SCONO_x technology comprises a five-step, batch process that takes place in three separate catalytic reactors (SCONO_xTM, SCOSO_xTM and reformer). The SCONO_x and SCOSO_x catalysts are positioned inside the HRSG, and the reformer may be either positioned inside the HRSG or provided as an external skid-mounted unit. The batch process operates in a repeating series of transient chemical reactions. To accommodate the batch processing, SCONO_x relies on an extensive system of moving parts (rotating shafts, dampers, and damper seals) that are subjected to the hot, turbulent flue gas stream. Following is a simplified summary of the five-step process:

In the first step, NO_x is oxidized to NO₂, CO is oxidized to CO₂, and NO₂ is absorbed by the SCONO_x catalyst. The catalyst is coated with potassium carbonate (K₂CO₃), and as the catalyst absorbs NO₂, the potassium carbonate coating is gradually converted to potassium nitrate (KNO₃) and nitrite (KNO₂) while giving off carbon dioxide. After several minutes (12 minutes at the two small-scale facilities that have operated with SCONO_x), all of the potassium carbonate coating has been converted, and the catalyst will absorb no more NO₂.

In the second step, the SCONO_x catalyst is regenerated so that it will again absorb NO₂. A section of the SCONO_x catalyst is sealed off in a compartment by closing dampers equipped with seals. Regeneration gas containing hydrogen and carbon dioxide is then piped into the sealed compartment. The hydrogen and carbon dioxide react with the potassium nitrate and nitrite (produced in the first step) to recreate the original catalyst coating material, potassium carbonate, while giving off nitrogen gas and water. At the completion of the second step, the

dampers are opened to release the gases that remain following regeneration, and the first step is then repeated.

At any given time, the majority of the catalyst is in contact with the flue gas and absorbing NO_2 , while a portion of the catalyst is isolated and undergoing regeneration. After the isolated portion has been regenerated, the next set of dampers close and the next portion of the catalyst is isolated and regenerated. This cycle repeats continuously and, as a result, each section of the catalyst is regenerated about every 15 minutes.

Because the SCONOx catalyst is readily poisoned (deactivated) by sulfur compounds, such compounds must be removed from the flue gas upstream of the SCONOx catalyst. The SCOSOx system is positioned upstream of the SCONOx catalyst to perform this critical function. Even applications firing exclusively pipeline quality natural gas need to be equipped with a SCOSOx catalyst. The SCOSOx catalyst is analogous to the SCONOx catalyst, except that it favors the oxidation and absorption of sulfur compounds instead of nitrogen oxides.

In the third step, sulfur compounds are oxidized to SO_3 , and the SO_3 is absorbed by the SCOSOx catalyst. The catalyst is coated with a proprietary “SORBER” material, and as the catalyst absorbs SO_3 , the SORBER gradually becomes saturated with SO_3 . After several minutes (12 minutes at the one small-scale facility that has operated with SCOSOx), the SORBER is completely saturated, and the catalyst will absorb no more SO_3 .

In the fourth step, the SCOSOx catalyst is regenerated so that it will again absorb SO_3 . This process is analogous to the SCONOx catalyst regeneration (the second step), and it uses the same regeneration gas. It is important that the SCOSOx catalyst be fully heated to its operating temperature of 600 to 700°F, because at temperatures below 450°F, the SCOSOx regeneration reaction forms extremely poisonous hydrogen sulfide gas (H_2S). At its full operating temperature, the SCOSOx regeneration reaction forms sulfur dioxide (SO_2). As with the SCONOx catalyst regeneration, a section of the SCOSOx catalyst is first sealed off in a compartment by closing dampers equipped with seals before the regeneration gas is admitted. After regeneration is complete and before the dampers are opened, the spent regeneration gas containing SO_2 is purged from the compartment, piped downstream of the SCONOx catalyst, mixed into the flue gas stream, and thereby vented to the atmosphere.

In the fifth step, the regeneration gas is produced that is required for use in regeneration of the SCONOx and SCOSOx catalysts. This regeneration gas, containing hydrogen and carbon dioxide, is produced in a catalytic reactor known as a reformer. In this reactor, the methane contained in natural gas is “reformed” by a reaction with steam. Because the reformer catalyst is readily poisoned by sulfur compounds, such compounds must be filtered out of the natural gas feedstock upstream of the reformer.

The SCONOx™ catalyst must be recoated with potassium carbonate every 6 to 12 months. The frequency of recoating depends on the sulfur content in the fuel and the effectiveness of

5.2 Air Quality

the SCOSOx catalyst. The recoating consists of removing the catalyst modules from the HRSG and bathing each module in potassium carbonate, the active ingredient of the catalyst. The SCOSOx catalyst also requires recoating, but due to limited operating experience with the SCOSOx catalyst, it is uncertain how often recoating will be required. However, it is expected that the SCOSOx catalyst will require recoating at least annually.

The SCONOx literature implies that it can achieve NO_x levels of 2.0 ppm or lower. However, the 5 MW installation at the Genetics Institute in Massachusetts (the only installation providing operating experience with both SCONOx and SCOSOx) has had great difficulty in meeting permitted levels on a regular basis. Furthermore, commercial guarantees have been extremely limited in acceptance of liability, which has required projects to include permit language allowing retrofit to a different technology if the SCONOx fails to meet expectations.

Feasibility: There are currently five SCONOx™ units in commercial operation worldwide. The SCONOx system has been in operation since December 1996 at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This plant consists of a GE LM2500, approximately 28 MW in size, roughly one-sixth the size of an F Class gas turbine. Furthermore, significant changes have been made to the SCONOx system since its installation at the Federal Plant, such as an increase in design operating temperature from 300-350°F to 600-700°F. The currently available SCONOx system has only been operated on a 5 MW gas turbine at the Genetics Institute in Massachusetts. This application of SCONOx is on a unit that is less than one-thirtieth the size of the gas turbine proposed for the Palomar Energy Project. Three other units were recently installed, two on 13 MW Solar Titan gas turbines at the University of California, San Diego, and one on a 8 MW Allison gas turbine at Los Angeles International airport.

Alstom (formerly ABB Power Generation) has an exclusive licensing arrangement with Goal Line for application of SCONOx on gas turbine power plants larger than 100 MW. Alstom has indicated that scale-up and engineering work will be required before SCONOx can be offered with commercial guarantees for large turbines¹. Scale-up and reliability issues that remain to be resolved (problems with catalyst poisoning, damper seal leakage, regeneration gas mal-distribution, etc.) are documented in an “Independent Technical Review” commissioned by Alstom and prepared by Stone & Webster (February 22, 2000). California electric generating projects such as the La Paloma and Otay Mesa projects have proposed to install SCONOx systems, but the projects' permits allow for switching to another technology should SCONOx fail to meet performance standards. The La Paloma project has indicated that use of SCONOx would be for the purpose of demonstrating this technology to be

¹ Charles L. Fryxell in “Revised Preliminary Determination of Compliance” for the High Desert Power Project, December 16, 1998, citing a Letter from Kreminski/Broemmelsiek (ABB Power Generation) to the Massachusetts Department of Environmental Protection dated November 4, 1998; Letter from Chris Broemmelsiek to Gary Lambert, U.S. Generating Company, December 7, 1998.

achieved in practice². However, subsequently the La Paloma project dropped its plans to install SCONOx. Further, the Otay Mesa project was recently sold to Calpine and they have decided not to use SCONOx for the Otay Mesa project.

SCONOx™ is an emerging technology. However, the technology has not yet been achieved in practice on large gas turbines.

Energy and Environmental Impacts: The SCONOx™ technology will have a larger energy impact than an SCR system for several separate reasons:

- The flue gas pressure drop due to the catalyst is 5 inches of water column, imposing a higher fuel penalty to overcome the increased backpressure.
- SCONOx requires natural gas consumption for use during the regeneration process. The increased natural gas consumption associated with the regeneration process is approximately 3,800 cubic feet per hour, which is approximately 0.25 percent of the total heat input per CTG.
- SCONOx requires considerable steam consumption as a carrier gas for the regeneration gas, further adversely impacting overall efficiency. Steam consumption is approximately 26,000 pounds per hour for each CTG, which is approximately equivalent to 2 MW of lost generation per CTG, or a total of 4 MW for a two-unit facility such as the Palomar Energy Project.

The SCONOx and SCOSOx catalysts require frequent recoating, and wastes associated with this process may require special treatment or disposal. Also, the SCOSOx catalyst has the potential to produce H₂S as a byproduct if the catalyst is not maintained at a temperature above 450°F.

2. Dry Low-NO_x and Selective Catalytic Reduction (SCR)

Dry low-NO_x (DLN) is a combustion zone NO_x control technology that reduces thermal NO_x formation without water or steam injection. This technology premixes the fuel and air in order to reduce maximum flame temperatures. It is employed by several gas turbine vendors.

Selective Catalytic Reduction (SCR) is a post-combustion control technique for reduction of NO and NO₂ emissions in the turbine exhaust stream to nitrogen and water. Aqueous ammonia (NH₄OH) or anhydrous ammonia (NH₃) is injected into the flue gas stream as a reducing agent prior to passage through a catalyst bed.

The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction, thereby promoting the breakup of NO and NO₂ to nitrogen and water. Performance and effectiveness of SCR systems is directly dependent upon the temperature of the flue gas

² 1999 La Paloma Application for Determination of Compliance. Pg. 4-8.

5.2 Air Quality

when it passes through the catalyst, as well as adequate mixing with the ammonia reagent, among other factors. Control efficiencies of 80 to greater than 90 percent may be achieved with SCR.

Feasibility: The combination of DLN with SCR technology is commercially available and installed on numerous large gas turbines. Very low NO_x emission levels have been guaranteed and permitted based on the combined use of these control technologies. A number of projects in California and elsewhere have recently proposed NO_x emission levels as low as 2.0 to 2.5 ppmvd at 15 percent O₂. Based on these proposals, EPA Region IX has recommended 2.0 ppmvd at 15 percent O₂ as the LAER target.

Energy and Environmental Impacts: The use of SCR results in slightly increased energy usage. SCR systems require energy to vaporize ammonia and to operate the blowers necessary to provide dilution air for mixing with the ammonia. There is also energy usage due to the additional pressure drop (about 3.5 inches of water column) that results from the use of the catalyst. This additional pressure drop causes a decrease in turbine efficiency, which is reflected in higher fuel usage than would be the case if no SCR were utilized.

Environmental impacts associated with the use of SCR may result from the usage and storage of ammonia, as well as the disposal of spent catalyst. Ammonia is a commonly used industrial, agricultural, and household chemical. However, it is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Palomar will utilize aqueous ammonia for the SCR system, as this form of ammonia has much less potential for risk to human health in an accident than does anhydrous ammonia. A Risk Management Plan (RMP) will be prepared for the Palomar Energy Project, if required by the California Accidental Release Prevention program provisions.

During SCR operation, not all of the ammonia injected for NO_x control is consumed. As a result, small quantities of ammonia are emitted to the atmosphere through the exhaust stack. This is commonly referred to as "ammonia slip" and is a phenomenon that is common to all SCR installations. State-of-the art controls are used to minimize ammonia emissions and to ensure compliance with the ammonia slip limit of 10 ppmvd.

The most common commercial SCR catalysts are vanadia/titania based, where vanadium pentoxide (V₂O₅) is used as the active catalyst compound. During normal usage and operation, SCR catalysts are not considered to be hazardous. Once reactivity of the catalyst deteriorates such that it must be replaced, the catalyst must be handled as a hazardous waste when it is disposed. Vanadium is classified by the EPA as a hazardous waste, and as such requires disposal in a RCRA hazardous waste (Subtitle C) landfill. Catalyst manufacturers may accept the return of deactivated catalyst that they manufactured. Since the use of DLN reduces the amount of NO_x produced and therefore reduces the amount of NO_x that must be removed by the SCR, there is a reduction in the amount of catalyst required to reach the targeted emissions, and this reduces the amount of catalyst that eventually must be disposed of or recycled.

3. Catalytica XONON™

The XONON™ technology works in the combustion zone to prevent NO_x formation through the use of a catalyst module within the combustor to reduce maximum combustion temperatures, thereby inhibiting thermal NO_x formation. With the XONON™ system, a portion of the fuel is combusted flamelessly within the catalyst module, followed by completion of the combustion process downstream of the catalyst.

According to literature (www.catalyticaenergy.com) provided by Catalytica Energy Systems, XONON™ combustors have reduced combustion turbine NO_x emissions to as low as 3 ppm in laboratory and pilot tests. Unlike SCONOX™ or SCR, flameless combustion requires no down-stream clean up device, but rather prevents the formation of thermal NO_x during combustion of the fuel. This technique avoids the need for ammonia injection and avoids system efficiency losses due to catalyst back pressure. The XONON™ technology actually replaces the traditional diffusion or lean pre-mix combustion cans of the combustion turbine.

In a typical combustor, fuel and air are burned at flame temperatures that may approach 2,700°F. Since the NO_x formation rate is exponential with flame temperature above about 2,000°F, thermal NO_x is formed within the combustors. The combustor exhaust is then diluted with cooling air to get the gas temperature below about 2,400°F, which is the upper temperature limit of the metal parts that make up the power turbine. With the XONON™ system, a fuel/air mixture is oxidized across several small catalyst beds to “burn” fuel at less than the flame temperature at which thermal NO_x formation begins. The XONON™ combustor does, however, utilize a partial flame downstream to complete the combustion process (burnout zone) and unavoidable small amounts of NO_x emissions are generated within this zone. Resulting emissions are being guaranteed at 5 ppm for some small turbine applications (less than 3 MW) and have been demonstrated as low as 3 ppm under test conditions. Like all catalysts, the XONON™ combustor catalyst performance can be expected to “age” with time. Unlike other catalysts, the XONON™ combustors can be easily changed out with a simple combustor replacement.

Feasibility: Enron had proposed to utilize the XONON™ system at a 510 MW power plant (the Pastoria Project) proposed to be sited in the San Joaquin Valley, California. This project was permitted and Catalytica had planned to deliver the first XONON™ systems to Enron in early 2001. The proposed NO_x emission rate for this project is 2.5 ppmvd. The applicant had stated that General Electric will, “on a best efforts basis”, deliver the XONON™ combustion system with full commercial guarantees in time for commencement of operation of the project. General Electric also had the right to substitute DLN/SCR if necessary to meet the project’s startup schedule”. In the spring of 2001, Catalytica and GE decided that the delivery date of January 2003 was too early to ensure that the XONON™ system could be ready to meet the strict emission rates. GE exercised the option to substitute alternative emissions control technology.

5.2 Air Quality

XONON™ does not currently represent an available control technology for the GE Frame 7FA (or any other 170 MW class turbine). While XONON™ is being sold commercially for certain (mostly smaller) engine models, it has so far been only been offered for large industrial gas turbines for the Pastoria project (but was then not able to meet the schedule). According to Catalytica, a joint venture agreement is in place with GE to eventually develop XONON™ as Original Equipment Manufacturer (OEM) and retrofit equipment for the entire GE turbine line. This agreement was reached after a successful demonstration of XONON™ on a GE 9F at GE's test facility in Schenectady, NY. It is critical to note that General Electric does not currently offer a XONON combustor option for 7FA or any other large industrial turbine. Therefore, XONON™ does not currently represent an available control technology for the Palomar project.

Energy and Environmental Impacts: Since XONON™ is a combustion zone device, it does not use ammonia or other catalysts to reduce NO_x. It also does not require frequent washing, frequent damper movements, or the potential for fouling and release of sulfur compounds. Therefore, it does not have the potential for environmental impacts that exists for SCONOX™ or SCR. However, it currently cannot meet the same control efficiency of these other devices.

4. Water/Steam Injection and SCR

A similar, but perhaps slightly less effective NO_x emission control technology than DLN and SCR, is the combination of water or steam injection followed by SCR. Injection of water or steam provides a heat sink absorbing some heat of combustion, thereby reducing maximum flame temperatures and hindering the formation of thermal NO_x. Water or steam injection alone can reduce NO_x emissions to a level of 25 to 42 ppmvd at 15 percent O₂. Additional reduction can then be achieved with an SCR down to perhaps 5 ppmvd at 15 percent O₂.

An important aspect of this technology is the production of sufficient quantities of ultra-pure water free from dissolved or suspended solids that could damage the turbine. Water for injection must meet rigorous water quality requirements for various parameters, which include silica content and suspended solid levels.

Feasibility: While this technology is feasible, it cannot consistently meet the lower emission rates achievable by DLN and SCR.

Energy and Environmental Impacts: Water injection ratios are generally less than one pound of water injected per pound fuel burned. Steam injection ratios are one to two pounds of steam per pound fuel burned. Water injection requires lower injection ratios for an equivalent NO_x reduction because of water's lower temperature and latent heat of vaporization. The use of water or steam injection significantly increases plant water use when compared to dry low NO_x combustors and lowers overall plant efficiency. CO emissions are significantly higher compared to DLN.

SCR energy and environmental impacts are the same as discussed above. However, because of the higher turbine outlet NO_x emissions that are achieved with water/steam injection, NO_x control efficiencies required of the SCR are higher than with DLN. This would require more catalyst volume and/or higher ammonia injection rates, increasing overall ammonia usage and ammonia slip. It is also likely to result in more frequent catalyst replacement, with the subsequent impact of additional catalyst disposal or recycling requirements.

5. Other Technologies

There are other technologies that could be considered in this Top-Down analysis, including SCR alone (without DLN or water/steam injection), DLN alone (without SCR), and water/steam injection alone (without SCR). However, these technologies are not capable of achieving NO_x emission rates equivalent to those discussed above (2.0 to 2.5 ppmvd at 15 percent O₂).

LAER Determination for NO_x

Consistent with EPA guidance, the Palomar Energy Project proposes LAER for NO_x to be 2.0 ppmvd at 15 percent O₂ over a 3-hour rolling average, to be achieved with DLN and SCR in combination. Ammonia emissions will be limited to 10 ppmvd at 15 percent O₂. Other technologies are either not "achieved in practice" for gas turbines in Palomar's size range, or do not offer equivalent NO_x control efficiency.

5.2.1.3 Assessment of CO, VOC and HAP Control Technologies

CO and VOC Formation

CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion, which are used to reduce NO_x formation, can be counterproductive with regard to CO emissions.

VOC emissions occur during the combustion process due to incomplete oxidation of hydrocarbons contained in the fuel. VOC are defined as non-methane and non-ethane hydrocarbons that are emitted from the gas turbine. VOC formation is limited by ensuring complete and efficient combustion of the fuel in the gas turbine. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize VOC emissions. Some amount of VOC control is achieved by the use of an oxidation catalyst, and the amount of VOC control obtained from an oxidation catalyst is dependent on the type of hydrocarbons that make up the VOCs.

Gas turbine manufacturers have optimized DLN such that the tradeoffs associated with the formation of NO_x, VOC, and CO emissions are optimized to reduce all three to the maximum

5.2 Air Quality

extent feasible. The use of water or steam injection to reduce NO_x emissions can significantly increase CO emissions. Post-combustion controls, such as oxidation catalysts, can also be used to reduce CO and VOC emissions.

Control Technology Assessment

Only one control technology, an oxidation catalyst, is used for post-combustion control of CO, VOC, and HAP emissions.

Catalytic oxidation is a post-combustion control technology primarily aimed at reduction of CO emissions. Oxidation catalysts operate at elevated temperatures within the HRSG. In the presence of an oxidation catalyst, excess O_2 in the turbine exhaust reacts with CO to form CO_2 . No chemical reagent is necessary. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic.

Feasibility: Oxidation catalysts for CO control have been used extensively and there is significant experience with the technology. Oxidation catalysts also have the benefit of reducing VOC and HAP emissions.

Energy and Environmental Impacts: An oxidation catalyst located downstream of the gas turbine exhaust will increase the back pressure on the gas turbine. The additional backpressure of two inches of water column reduces the gas turbine output slightly for the same fuel firing rate. At the flue gas temperatures leaving the gas turbine (900° to $1,135^\circ\text{F}$), the oxidation catalyst can cause some SO_2 in the flue gas to oxidize to SO_3 . The operation of the gas turbine on natural gas only, which has minimal sulfur content, minimizes the amount of SO_x that is formed.

BACT Determination for CO

The Palomar project proposes to achieve CO emissions of no more than 4.0 ppmvd at 15 percent O_2 on a 3-hour rolling average through the exclusive firing of natural gas fuel and use of an oxidation catalyst. This level is lower than the current BACT of 6.0 ppmvd recommended by the California Air Resources Board (1999) and also lower than a 6.0 ppm level recently determined as BACT for the Midway-Sunset project.

LAER Determination for VOC

Although SDAPCD Rule 20.3(d)(1)(v) requires BACT for sources that emit less than 50 tons per year of VOC, an oxidation catalyst represents LAER for VOC. Palomar proposes to achieve VOC emissions of not more than 3.0 ppmvd at 15 percent O_2 on a 3-hour rolling average through the use of an oxidation catalyst.

Most of the hazardous air pollutants (HAP) emitted by natural gas-fired turbines are VOCs. Therefore, an oxidation catalyst will also reduce the total emissions of HAP. Consistent with previous determinations, e.g., Otay Mesa, a 50 percent reduction of HAP emissions is considered achievable with an oxidation catalyst.

5.2.1.4 Assessment of SO_x and PM₁₀ Control Technologies

A review of recent BACT determinations by the EPA and others indicates the use of natural gas as an exclusive fuel for the turbines represents the most stringent control available for SO_x and PM₁₀. Typically, natural gas has only trace amounts of sulfur (0.2 to 0.8 grains per 100 standard cubic feet) present as an odorant. Natural gas typically contains only trace quantities of noncombustible material. Natural gas is among the cleanest burning and lowest SO_x and PM₁₀-producing fuels available. The manufacturer's standard operating procedures include filtering the turbine inlet air and good combustion controls. No combustion or post-combustion controls were identified during this review. Therefore, SO_x and PM₁₀ emissions will be controlled through the use of clean burning, pipeline quality natural gas.

5.2.1.5 Summary of Proposed BACT/LAER

The proposed BACT/LAER for the Palomar project is shown in Table 5.2-4.

Table 5.2-4 Proposed Palomar Energy Project BACT/LAER

Pollutant	Control Technology	Emission Rate (ppmvd at 15% O₂)
NO _x	Dry low-NO _x combustors and selective catalytic reduction with NH ₃ injection at 10 ppmvd	2.0 (3-hour average)
CO	Good combustion practices and use of an oxidation catalyst	4.0 (3-hour average)
VOC	Good combustion practices and use of an oxidation catalyst	3.0 (3-hour average)
PM ₁₀	Good combustion practices and exclusive use of natural gas fuel	--
SO _x	Exclusive use of natural gas fuel	--

5.2.3 Environmental Impacts

This section provides a discussion of the air quality impacts from criteria pollutant emissions from the project. Section 5.15 provides a discussion of the impacts to public health from potential emissions of HAP.

5.2.3.1 Emissions

This section provides a discussion of the criteria pollutant emissions from the Palomar project. Emissions have been estimated for three phases of the project: construction, commissioning, and operation. These phases are discussed below.

Construction

During construction of the Palomar project, there will be emissions similar to those associated with any large industrial construction project. Onsite emissions will arise primarily from heavy-duty vehicles and equipment. Onsite fugitive dust emissions also will be generated during site preparation and during construction. Offsite emissions will occur from construction worker vehicles and material delivery trucks. The construction related emissions are transient in nature, and may cause some localized short-term PM₁₀ impacts since the area already exceeds the California 24-hour AAQS.

The Palomar project will include the construction of 1.1-mile 16-inch diameter water supply and eight-inch diameter wastewater return pipelines. To relieve a bottleneck in a segment of the existing SDG&E gas system located about one mile northeast of the plant site, SDG&E will construct an upgrade consisting of approximately 2,600 feet of 16-inch pipeline.

Construction of the power plant will include site preparation, as well as structural, mechanical, and electrical construction. These activities are anticipated to take place over a 21-month construction period. Rough grading of the power plant site will have been completed as part of development of the industrial park within which the plant site is located. This will occur before Palomar project construction begins. Thus, the site preparation element of Palomar project construction will include some soil compaction and final grading, as well as minor excavations for utilities installation, and installation of foundations and footings. Water supply/wastewater return pipeline construction is anticipated to occur over a six-month period; natural gas pipeline construction is anticipated to require about three months.

Table 5.2-5 summarizes peak and annual average hourly onsite emissions during construction, and Table 5.2-6 summarizes annual offsite motor vehicle emissions. Details of the construction emission calculations are presented in Appendix E.2.

Commissioning

Following construction of the power plant and prior to commercial operation, the combustion turbine generators (CTGs), steam turbine generator (STG), emissions control equipment, heat recovery steam generators (HRSGs), and other plant equipment will be tested and tuned. Further, the HRSGs, steam piping, condensers, and other equipment handling steam and condensate will be cleaned of dirt, oil, mill scale and debris. This cleaning is usually accomplished with steam blows. All of these commissioning operations will require operation of the CTGs at loads from 0% to 100% of full load. During much of this period, the emissions from the plant will be higher than the normal operating and start-up emissions, because the CTG burners may not yet be tuned for optimal emissions and the post-combustion emissions control equipment will not yet be in operation.

Table 5.2-5 Worst Case Onsite Construction Activity Emissions

Location	CO (lbs/hr)		VOC (lbs/hr)		NO _x (lbs/hr)		SO _x (lbs/hr)		PM ₁₀ (lbs/hr)	
	Peak	Ann. Avg.	Peak	Ann. Avg.	Peak	Ann. Avg.	Peak	Ann. Avg.	Peak	Ann. Avg.
Power Plant	81	40	6.0	2.4	27	9.1	0.6	0.2	2.4	1.2
Water Pipelines	4.7	0.3	0.8	0.1	5.4	0.4	0.1	< 0.05	0.4	< 0.05
Natural Gas Pipeline	2.9	0.2	0.6	< 0.05	3.9	0.2	0.1	< 0.05	0.3	< 0.05

Table 5.2-6 Offsite Construction Motor Vehicle Emissions

Location	CO (tons/yr)	VOC (tons/yr)	NO _x (tons/yr)	PM ₁₀ (tons/yr)
Power Plant	45	7.1	9.4	2.0
Water Pipelines	1.3	0.2	0.3	0.1
Natural Gas Pipeline	0.6	0.1	0.2	< 0.05
TOTAL	47	7.4	9.9	2.1

Table 5.2-7 summarizes the anticipated emissions during the commissioning period. The commissioning period is expected to be accomplished with less than 300 hours of operation on each of the CTGs.

Table 5.2-7 Emissions During Commissioning Period

Location	CO	VOC	NO _x
Maximum Hourly per CTG (lb/hr)	159	14.7	118
TOTAL for two CTGs (tons)	47.6	4.4	35.3

Operational Emissions

The Palomar project will be operated as a merchant power plant. This means that it will respond to the market place as needed, and hence may start up and shut down frequently throughout the year. The plant will also employ duct firing for peaking capacity. Therefore, normal operating emissions must account for emissions during startup and shutdown, as well as base and maximum load operations. Each of these operating modes is discussed below, and detailed emission estimates are provided in Appendix E.3.

Start-up Emissions

Combustion turbine startups are expected normally to last from about 2 to 4 hours each, depending on how long the turbine has been shut down and depending on whether delays are encountered during startup. Emission characteristics during start up periods will be different than those during normal operation. This is because during startups, the CTG combustors mix fuel and air in a different manner than during normal operation, and also because the post-combustion emission control equipment is not at its proper operating temperature. Duct firing will not be employed during the startup sequence.

Startup emissions have been estimated as follows:

- 50 extended starts (up to 4 hours in duration) per year and 182 regular starts (up to 2 hours in duration) per year per CTG. This yields a total of 100 extended starts and 364 regular starts per year for the total project, or 1,128 total startup hours per year;
- 232 shutdowns (up to 0.5 hours in duration) per year per CTG, or a total of 232 hours shutdown for the overall facility;
- Both units could undergo startups and/or shutdown on any given day; and.
- The SCR and oxidation catalyst will provide limited emissions reduction during startup and shutdown, and the NO_x and CO emission control efficiency will vary during the startup sequence.

Table 5.2-8 summarizes startup and shutdown emissions, based on a review of the performance data contained in Appendix E and the operating parameters stated above. PM₁₀ and SO₂ emissions are not included, because emissions of these pollutants during startup and shutdown would not be significantly different from normal operations. It is important to note that these assumptions were used in order to determine maximum annual emissions and are not intended as permit limits for the number or duration of startups or shutdowns.

**Table 5.2-8 Combustion Turbine Startup and Shutdown Emissions
(Both Turbines)**

Pollutant	Extended Startup (lb/event)	Regular Startup (lb/event)	Shutdown (lb/event)
NO _x	200	140	25
CO	1,000	920	160
VOC	100	74	12

Hourly CTG Emissions During Normal Operation

Performance data were developed for the CTGs in order to assess the expected hourly emissions during various load and temperature conditions. These operating cases represent four operating scenarios (100 percent load with duct firing, and 100 percent, 75 percent, and

50 percent loads without duct firing) at three different ambient temperatures: maximum summer (110°F), annual average (62°F) and winter minimum (20°F). The performance data are presented in Appendix E.3 and summarized in Table 5.2-9.

Table 5.2-9 Emission Estimates (Each Turbine, pounds per hour)

Load	Pollutant	Ambient Temperature		
		20°F	62°F	110°F
100% (With Duct Firing)	NO _x	14.9	13.9	13.2
	CO	18.1	16.9	16.1
	VOC	7.3	6.8	6.8
	SO ₂	4.5	4.2	4.0
	PM ₁₀	14.0	13.8	14.0
100% (Without Duct Firing)	NO _x	13.4	12.5	11.7
	CO	16.3	15.3	14.3
	VOC	4.0	3.8	3.6
	SO ₂	4.1	3.8	3.6
	PM ₁₀	11.1	11.1	11.1
75% (Without Duct Firing)	NO _x	10.7	10.2	9.6
	CO	13.1	12.4	11.7
	VOC	3.1	3.0	2.9
	SO ₂	3.3	3.1	2.9
	PM ₁₀	11.1	11.1	11.1
50% (Without Duct Firing)	NO _x	8.5	8.1	7.6
	CO	10.3	9.9	9.3
	VOC	2.6	2.5	2.5
	SO ₂	2.6	2.5	2.3
	PM ₁₀	11.1	11.1	11.0

Cooling Tower Emissions

Cooling tower emissions are related to the amount of drift released from the tower. The Palomar cooling towers will have a drift rate of 0.0005 percent and a total circulation rate of 130,000 gallons per minute. Based on analysis of the reclaimed water to be used for the project and the planned cycles of concentration, the maximum total dissolved solids concentration in the cooling tower drift is expected to be 4,000 mg/l. A ratio of 50 percent of the TDS is expected to be emitted as PM₁₀. Thus, the emission rate from the cooling tower is calculated to be 0.65 pounds of PM₁₀ per hour, or 2.9 tons per year if operated continuously.

Worst-Case Daily Emissions

Worst-case daily emissions have been calculated on a pollutant-by-pollutant basis by assuming the worst-case hourly operating scenario for any of the four load points and three ambient temperatures. For NO_x, CO, and VOC, the turbines are assumed to operate 20 hours

5.2 Air Quality

at maximum load, plus 4 hours in startup conditions. PM₁₀ and SO₂ are based on 24 hours of maximum operation. The worst-case daily emissions estimates have been used to determine if ambient air quality modeling, BACT, and offset requirements have been triggered, and to establish maximum daily emissions. The estimated daily emissions are shown in Table 5.2-10.

Table 5.2-10 Project Daily Maximum Emissions (Both Turbines and Cooling Tower)

Pollutant	Maximum Daily (lb/day)
NO _x	796
CO	1,720
VOC	392
SO _x	216
PM ₁₀	687

Facility Potential to Emit

Annual emissions at 62 °F (average annual temperature) per turbine have been calculated as follows:

- 200 hours per year of extended startup emissions per turbine (50 starts per turbine, each lasting 4 hours).
- 364 hours per year of regular startup emissions per turbine (182 starts per turbine, each lasting 2 hours).
- 2,000 hours per year of maximum load (100 percent load with duct firing) operation per turbine.
- 6,080 hours per year at base load (100 percent load without duct firing) operation per turbine.
- 116 hours per year in shutdown per turbine (232 shutdowns per turbine, each lasting one-half hour).
- No downtime for maintenance or when shutdown has been assumed.

The Palomar project's potential to emit (PTE) is shown in Table 5.2-11. These emissions have been used to determine the various permitting requirements including the amount of emission offsets required.

Table 5.2-11 Project Annual PTE (Both Turbines and Cooling Tower)

Pollutant	Annual Average (tons/year)
NO _x	124
CO	254

VOC	47
SO _x	33
PM ₁₀	105

5.2.3.2 Air Quality Impact Assessment

This section addresses the air quality impacts from operation of the Palomar project. Potential impacts due to the criteria pollutant emissions that were described in the preceding section were determined using air quality dispersion models. An impact assessment was performed with respect to the ambient air quality in the project vicinity, the air quality in protected "Class I" areas, and Air Quality Related Values (AQRVs) such as visibility in the Class I areas. A health risk assessment related to the Palomar project's emissions of toxic air contaminants is presented in Section 5.15.

Modeling Methodology

An air quality impact analysis (AQIA) is required for the Palomar project, since the project's PTE is greater than the SDAPCD AQIA trigger levels and PSD significant emission rates for NO_x, CO, and PM₁₀. Although not required by SDAPCD Rule 20.3 for this project, SO₂ impacts also were determined.

Atmospheric dispersion modeling was conducted to evaluate the potential commissioning and operational impacts associated with the proposed project. The dispersion modeling analysis evaluated impacts in simple (at or below stack height) and elevated (above stack height) terrain. Dispersion modeling was performed to assess predicted project impacts against the federal PSD Significant Impact Levels (SILs), California and National Ambient Air Quality Standards (AAQS), Class II and Class I PSD increments, and Class I AQRVs. The following models were used for these assessments:

- Modeling supporting the Significant Impact Levels (SILs), Class II PSD increments, and AAQS analyses for permitting the project utilized the Industrial Source Complex Short Term 3 (ISCST3) dispersion model for impacts in simple terrain. The AERMOD model was used for these analyses in areas of elevated terrain.
- For Class I Wilderness Areas within 50 km of the facility, AERMOD was used to determine compliance with Class I PSD increments. Visibility analyses were performed with VISCREEN and the PLUVUE II model. VISCREEN and PLUVUE II are recommended by the EPA for refined assessment of visibility impacts within 50 km of combustion sources emitting optically active pollutants (SO₂, NO₂ and PM₁₀). CALPUFF was used to assess acid deposition.
- For Class I Wilderness Areas more than 50 km from the facility, CALPUFF was used to determine compliance with the Class I PSD increments, visibility, and acid

5.2 Air Quality

deposition. CALPUFF modeling followed guidance of the Federal Land Manager's Air Quality Related Values Workgroup Phase I Report (FLAG, 2000).

Details pertaining to the model selection, modeling methodology, meteorological data, receptors, land use, background air quality data, and post-processing of NO₂ impacts are provided in the modeling protocol for the project (Appendix E.4). Electronic model input and output files are contained on a compact disk (CD) that is provided as Appendix E.5.

Project modeling was done in a step-wise approach. First, the twelve operating scenarios, emissions and stack parameters shown in Appendix E.3, Table E.3-1 were modeled to determine the highest incremental concentrations ("maximum impacts"). The maximum impacts for all cases were then compared to the federal SILs. If the maximum impacts from the project were below the applicable SIL, EPA regulations do not require further cumulative modeling with respect to PSD increments or National AAQS. However, SDAPCD regulations and guidelines require further analyses of project impacts, as discussed in the following sections.

Construction Impacts

Construction-related emissions were modeled using the ISCST3 model version 00101. Appendix E.2 contains the detailed construction emissions, and Appendix E.4 contains the modeling protocol used for the analysis.

Emissions of criteria pollutants for the construction sources were modeled as area sources. Buoyancy and mechanical turbulence from the hot exhaust and mechanical turbulence from movement of the construction equipment were used to estimate the initial vertical dimension of the area source. Fugitive dust emissions and onsite motor vehicles were modeled as a single low-level area source since these emissions would almost all occur near ground level.

The modeling results show that the NO₂ (1-hour and annual averaging periods), CO (1 and 8-hour averaging periods), and SO₂ (1, 3, and 24-hour, and annual averaging periods) AAQS will not be exceeded during construction. PM₁₀ construction emission impacts could contribute to the existing exceedances of the state 24-hour PM₁₀ standard as shown in Table 5.2-12. The California annual PM₁₀ standard is nearly met by background alone, so even a slight impact could cause an additional exceedance. The peak 1-hour NO₂ impact was estimated using the ozone limiting method and 1998-2000 concurrent O₃ and NO₂ ambient monitoring data from the SDAPCD Escondido monitoring site.

Table 5.2-12 Estimated Construction Ambient Air Quality Impact

Pollutant	Averaging Period	Maximum Modeled Impact (µg/m³)	Background¹ (µg/m³)	Total Predicted Concentration² (µg/m³)	Ambient Air Quality Standard³
NO ₂	1-hour	151.9 ⁴	148 ⁴	300	470

5.2 Air Quality

	Annual	61.2 ⁶	--- ⁶	61 ⁶	100
CO	1-hour	5170	11,870	17,000	23,000
	8-hour	1447	6,123	7,570	10,000
SO ₂	1-hour ⁵	40.9	397	438	655
	24-hour	3.6	53	57	105
	Annual	0.8	8	9	80
PM ₁₀	24-hour	20.7	65	86	50
	Annual	5.1	28.5	34	30

¹ Background air quality data obtained from the Escondido station, except SO₂ is from the Chula Vista monitoring station.

² All concentration totals rounded to three or fewer significant figures.

³ Most stringent of federal or state ambient air quality standard for each pollutant and averaging period.

⁴ The ozone limiting method (OLM) was used to estimate the worst-case NO₂ impacts. The 1-hour background NO₂ concentration was determined to be the hour that resulted in the peak ozone limited impacts (including background NO₂ for each hour).

⁵ The maximum 1-hour impact with background for SO₂ is also below the 3-hour (1,300 µg/m³) AAQS.

⁶ Annual average NO₂ was computed as the annual average of the ozone limited 1-hour impacts. Background annual NO₂ concentrations are not obtainable using this method, therefore the total impact (project plus background) is presented in this table.

Significant Impact Analysis and Class II PSD Increments

As described in the modeling protocol, project emissions were modeled at various receptor domains surrounding the project site. AERMOD was used to determine impacts due to operational emissions in elevated terrain (above stack height), while ISCST3 was used in simple terrain (at or below stack height). In order to meet modeling guidelines and adequately characterize the impacts, many receptor domains were modeled. The maximum impacts when using ISCST3 occurred in the "MainISC" modeling domain, which included the facility fence line and near field receptors surrounding the project site. The maximum impacts when using AERMOD for the elevated terrain receptors occurred in the "West Hills" modeling domain, which is located approximately 2.0 miles (3.2 km) west-southwest of the project site. The overall maximum impacts are reported for each pollutant and averaging period. It is important to note that such maximum impacts occur infrequently, and that dispersion models tend to overestimate the short-term impacts.

Federal PSD regulations require that proposed major sources, such as the Palomar project, not contribute to air pollutant concentrations in excess of the PSD increments. Attainment areas are divided into Class I and Class II areas for the PSD increment analysis. More sensitive Class I areas (e.g., formally designated wilderness areas, national parks and monuments) are protected by the most stringent PSD increments, with the remainder of the attainment areas evaluated in terms of Class II PSD increments. The Palomar project vicinity is classified as a Class II area.

Table 5.2-13 shows the results of the AQIA with respect to the federal SILs and PSD Class II increments. The maximum impacts were predicted when using AERMOD, except 1-hour CO, which occurred in the MainISC receptor domain using ISCST3. Table 5.2-13 shows that

5.2 Air Quality

all project impacts are below the respective SIL for each pollutant and averaging period. Since the results are below the applicable SILs, no further PSD Class II increment analysis is required. Table 5.2-13 shows the PSD Class II increments for comparison purposes.

Table 5.2-13 Significant Impact and Class II PSD Increment Results

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu\text{g}/\text{m}^3$)	Significant Impact Level ($\mu\text{g}/\text{m}^3$)	Class II Increment ($\mu\text{g}/\text{m}^3$)
NO ₂	Annual	0.7	1	25
PM ₁₀	Annual	0.8	1	17
	24-hour	4.8	5	30
SO ₂	Annual	0.2	1	20
	24-hour	1.4	5	91
	3-hour	5.4	25	512
CO	8-hour	388 ¹	500	-- ²
	1-hour	1,250 ¹	2,000	-- ²

1 CO modeling based on startup emissions lasting for the entire averaging period.

2 PSD increments have not been enacted for CO by the federal Clean Air Act

Ambient Air Quality Standards Analysis

EPA regulations do not require an AQIA with respect to the National AAQS when results are modeled to be below the SILs, because impacts less than the SILs are deemed to not cause or contribute to violations of the National AAQS. However, SDAPCD Rule 20.3 requires an AQIA with respect to the California AAQS, even if project impacts are less than the SILs. In this analysis, modeled maximum impacts from the project during normal operations are added to maximum background concentrations monitored in the area. Maximum background concentrations of NO₂, CO, and PM₁₀ were taken from the Escondido monitoring station data (see Table 5.2-2), and maximum background SO₂ concentrations were taken from the Chula Vista monitoring station. Table 5.2-14 shows the results of this analysis.

As shown in Table 5.2-14, when modeled project impacts are added to ambient background levels, in all cases the sum was found to be below the National AAQS, and with one exception, below the California AAQS. The exception is the California 24-hour PM₁₀ AAQS, since ambient background levels measured at the Escondido monitoring station have already exceeded this standard on occasion (once in 1998, once in 1999, and twice in 2000, with annual average concentrations remaining relatively constant through the period).

Table 5.2-14 Maximum Ambient Air Quality Impact During Normal Operations

Pollutant	Averaging Period	Maximum Modeled	Background ($\mu\text{g}/\text{m}^3$)	Total Impact ¹	Ambient Air Quality
-----------	------------------	-----------------	---	---------------------------	---------------------

		Impact ($\mu\text{g}/\text{m}^3$)		($\mu\text{g}/\text{m}^3$)	Standard ²
NO ₂	1-hour	24.8 ³	191	216	470
	Annual	0.7 ³	44	45	100
CO	1-hour	30.1	11,870	11,900	23,000
	8-hour	10.6	6,123	6,030	10,000
SO ₂	1-hour	7.5	397	405	655
	3-hour	5.4	397	402	1300
	24-hour	1.4	53	54	105
	Annual	0.2	8	8.2	80
PM ₁₀	24-hour	4.8	65	69.8	50
	Annual	0.8	28.5	29.3	30

1 All total impacts rounded to three or fewer significant figures.

2 Most stringent of federal or state ambient air quality standard for each pollutant and averaging period.

3 Assumes 100 percent conversion of NO_x to NO₂.

Pursuant to SDAPCD Rule 20.3(d)(2), further analysis was performed with respect to the California 24-hour PM₁₀ AAQS. This rule required that the applicant demonstrate to the satisfaction of the Air Pollution Control Officer (APCO) through an AQIA, that the project will not cause additional exceedances of the California AAQS anywhere the standard is already being exceeded. To perform this analysis for the Palomar Energy Project, modeling was performed using the meteorology on specific days when monitored background PM₁₀ concentrations were between 45 and 50 $\mu\text{g}/\text{m}^3$ (the California standard is 50 $\mu\text{g}/\text{m}^3$). Six days were identified in the 3-year modeling period from 1998-2000 with background concentrations between 45 and 50 $\mu\text{g}/\text{m}^3$.

Based on the meteorological conditions on the six days, the modeled maximum project impacts occur about 2 miles west of the project site in the West Hills receptor domain, well outside of the Escondido urban area. This maximum impact location is not anomalous, and in fact, matches the results obtained based on the overall meteorological data. The West Hills area consists primarily of complex, vegetated terrain and it is considered highly unlikely that this area would experience the same background concentration levels observed at the downtown Escondido monitoring site, which is close to roadways and other sources of PM₁₀. In contrast, the Escondido monitoring station is located in the midst of the Escondido urban area, where maximum ambient background levels are expected to occur. Based on the meteorological conditions on the six days, the modeled maximum project impact at the Escondido monitoring station is only 0.2 $\mu\text{g}/\text{m}^3$. When the modeled impacts at the monitoring station (or anywhere else in the Escondido urban area) are added to the ambient background levels measured on the six days, the result does not exceed the California 24-hour PM₁₀ AAQS, as shown in Table 5.2-15. For this reason, and because project impacts are modeled

5.2 Air Quality

to be insignificant (i.e., below the SILs), it is concluded that the Palomar Energy Project will not cause additional exceedances of the California 24-hour PM₁₀ AAQS.

Table 5.2-15 Maximum Total PM₁₀ Impacts During Normal Operations

Date	Background ($\mu\text{g}/\text{m}^3$)	Project Impact ($\mu\text{g}/\text{m}^3$)	Case ¹	Total Impact ($\mu\text{g}/\text{m}^3$)
3/1/99	48	0.08	12	48
5/12/99	47	0.23	1	47
11/2/99	47	0.05	1	47
11/14/99	50	0.03	1	50
12/20/99	48	0.13	12	48
11/20/00	49	0.003	4	49

¹ Case corresponds to the load and temperature combinations shown in Appendix E, Table E.3-1.

Commissioning and Startup Impacts

An analysis was conducted of commissioning and startup emissions, which will be short-term duration events. However, hourly emissions of NO_x and CO will be higher than those expected during normal operations because the SCR and oxidation catalyst pollution control devices will not yet be optimized during the power plant commissioning and not operated at optimum conditions during startup. Therefore, modeling of commissioning and startup emissions was conducted separately from normal operations for comparison against the short-term AAQS for NO₂ and CO.

Commissioning

For commissioning, the average emission rates were modeled to determine the maximum 1-hour NO₂ concentrations, and the maximum 1-hour and 8-hour CO concentrations. Stack parameters representative of startup (i.e., 50 percent load) were used in the modeling since the 50 percent load parameters are expected to yield the worst-case dispersion of the CTG plumes. PM₁₀ and SO₂ emissions were not modeled, since the emission rates during commissioning are not expected to be significantly different from those during normal operations.

For CO, the maximum 1-hour and 8-hour concentrations during commissioning (including background) were 12,300 and 6,250 $\mu\text{g}/\text{m}^3$, respectively. These impacts were well below the 1-hour and 8-hour air quality standards of 23,000 $\mu\text{g}/\text{m}^3$ and 10,000 $\mu\text{g}/\text{m}^3$. The maximum 1-hour CO impact is predicted to occur at the western facility boundary, while the maximum 8-hour CO impact occurs in the elevated terrain located approximately 1.9 miles (3 km) west-southwest of the project site.

NO₂ modeling was performed using the average commissioning NO_x emission rate, assuming 100 percent conversion of NO_x to NO₂. Assuming 100 percent conversion, the NO_x emission rate of 118 lb/hr per turbine could produce an impact (plus background) greater than the 1-hour California standard of 470 µg/m³. As 100 percent conversion is an extremely conservative assumption, an ozone limiting analysis was performed to assess the NO₂ impacts with more reasonable assumptions of conversion from NO to NO₂.

The additional analysis showed that the maximum concentrations estimated using the ozone limiting method are governed by the observed background NO₂ concentration rather than the modeled NO_x concentration. The maximum ozone limited NO₂ impact, including background, of 225 µg/m³ occurred in the South Hills receptor domain, approximately 4.9 km south-southwest of the facility in elevated terrain. The Palomar source contribution to the maximum 1-hour NO₂ concentration was only 37.4 µg/m³ (17 percent) of the total impact, while the background concentration contributed 188 µg/m³ (83 percent) of the total impact. Therefore, when plausible conversion rates of NO to NO₂ are assumed using the ozone limiting method, commissioning emissions produce maximum 1-hour NO₂ concentrations well below the California standard of 470 µg/m³.

Based upon this analysis, emissions during the commissioning of the Palomar Energy Project are not expected to produce an exceedance of either California or federal AAQS for NO₂ or CO.

Startup

The modeling analysis for startup events consisted of the maximum short-term NO_x and CO emissions rates associated with extended startups and assuming stack release parameters for 50 percent load conditions. PM₁₀ and SO₂ emissions were not modeled, since the emission rates during startup are not expected to be significantly different from those during normal operations.

Results of the startup modeling analysis results are provided in Table 5.2-16. The startup results show that the maximum predicted impacts during turbine startup events will be well below the AAQS.

Table 5.2-16 Estimated Ambient Air Quality Impacts During Startup

Pollutant	Averaging Period	Maximum Modeled Impact (µg/m³)	Background ¹ (µg/m³)	Total Predicted Concentration ² (µg/m³)	Ambient Air Quality Standard ³
NO ₂	1-hour	266 ⁴	191 ⁵	457	470
CO	1-hour	1,250	11,870	13,100	23,000
	8-hour	388	6,123	6,510	10,000

5.2 Air Quality

- 1 Background air quality data for NO₂ and CO obtained from the Escondido monitoring station during the period 1998-2000.
- 2 All total impacts rounded to three or fewer significant figures.
- 3 Most stringent of federal or state ambient air quality standard for each pollutant and averaging period.
- 4 Assumes 100 percent conversion of NO_x to NO₂.
- 5 Maximum 1-hour NO₂ measured at the Escondido monitoring station.

5.2.1.3 PSD Class I Analyses

An analysis of the potential project impacts with respect to the PSD Class I increments was performed. There are two Class I areas (Agua Tibia and San Jacinto Wilderness Areas) within 62 miles (100 km) of the Palomar site. The locations of these areas with respect to the project are shown in Figure 5.2-2.

The AERMOD modeling was used to conduct the PSD Class I air quality analysis at Agua Tibia Wilderness Area (within 50 km) since all receptor elevations are above stack height. In addition to the air quality analysis, modeling to determine the impacts on visibility and acid deposition in Class I areas is also required. As discussed in the modeling protocol (Appendix E.4), the VISCREEN, PLUVUE II, and CALPUFF models were used for these analyses.

The results of this analysis are provided in Table 5.2-17. The results are well below the Class I increments, and are also below the proposed Class I significant impact levels (SILs).

5.2.1.4 Air Quality Related Values

PSD regulations require that an Applicant determine the project's potential impact on AQRVs that have been determined for the Class I area by the Federal Land Manager (FLM). In this case, since both Class I areas of interest are Wilderness Areas, the FLM is the U.S. Department of Agriculture, Forest Service (USFS).

AQRVs generally focus on visibility and acid deposition impacts in the Class I area. There are no uniform criteria or standards upon which a modeled impact is determined to be acceptable. For each Class I area the FLM applies judgement based on site-specific conditions and established guidelines. The applicable AQRV guidelines that are understood to apply to the project reflect FLAG (2000) and are described in the modeling protocol (Appendix E.4). The results of each analysis are provided below.

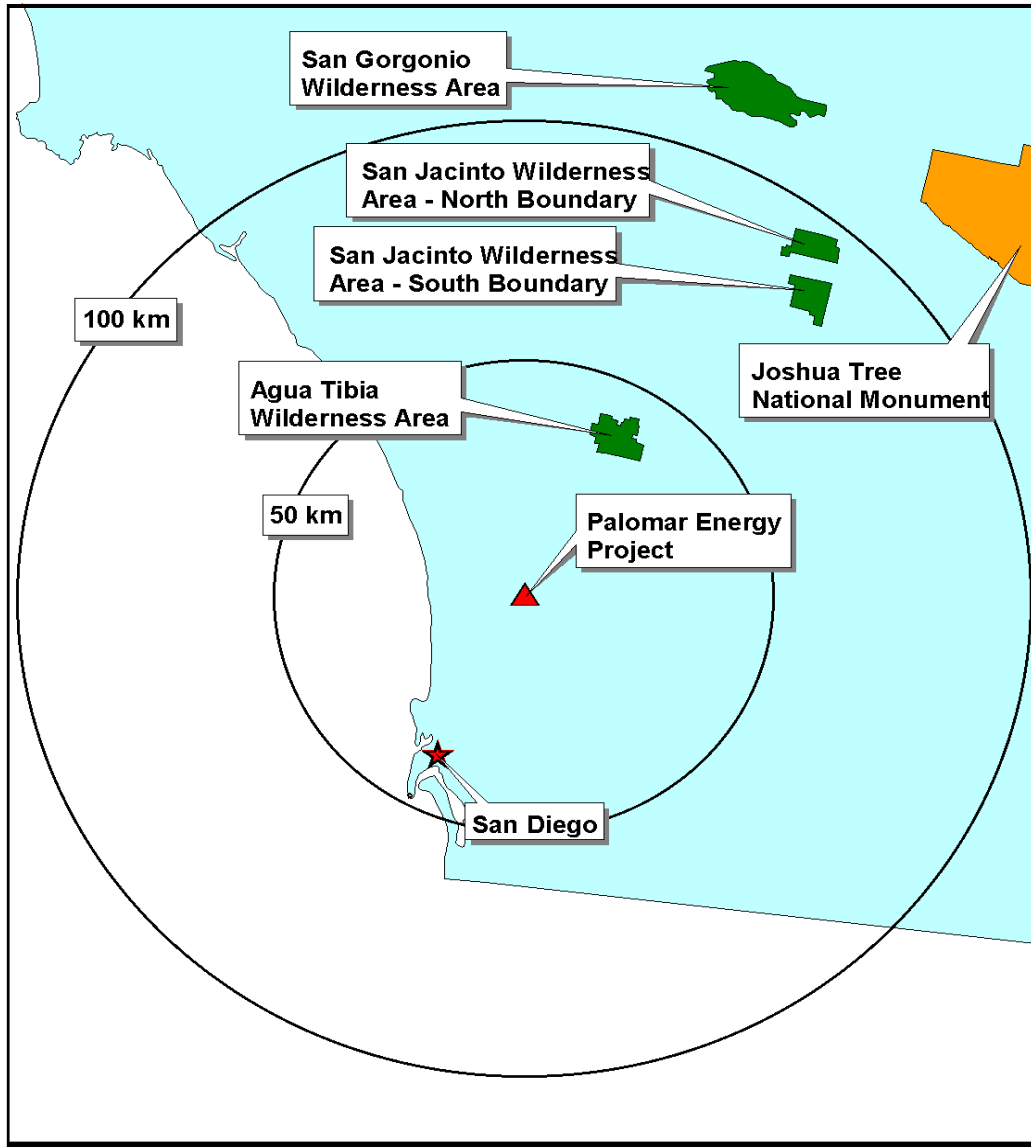


Figure 5.2-2 Project and Class I Area Locations

Table 5.2-17 Class I PSD Increment Results

Pollutant	Averaging Period	Agua Tibia Maximum Modeled Impact ($\mu\text{g}/\text{m}^3$)	San Jacinto Maximum Modeled Impact ($\mu\text{g}/\text{m}^3$)	Proposed Class I Area Significant Impact Levels¹ ($\mu\text{g}/\text{m}^3$)	Class I Area Increment ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	0.002	0.005	0.1	20
	24-hour	0.027	0.040	0.2	91
	3-hour	0.170	0.138	1.0	512
PM ₁₀	Annual	0.005	0.018	0.2	17
	24-hour	0.091	0.139	0.3	30
NO ₂	Annual	0.006	0.008	0.1	25

¹ Source: EPA proposed New Source Review reform, FR 7/23/96.

Visibility at Agua Tibia Wilderness Area

The first two levels for screening visibility impacts using VISCREEN at Agua Tibia Wilderness showed potential exceedances of the screening criteria for plume perceptibility and contrast. Therefore, a Level-3 plume visibility analysis was performed using the PLUVUE II model, which is recommended by EPA (1992). A detailed discussion regarding the meteorological conditions, plume observer distances, and background values is provided in the modeling protocol in Appendix E.4.

The results of the analysis are provided in Table 5.2-18 and indicate that all modeled values of plume perceptibility (ΔE) and contrast (C_p) are well below the screening thresholds of 2.0 and ± 0.05 , respectively (EPA, 1992). The largest values for each type of background are highlighted. For a sky background, the highest magnitude plume contrast is -0.007 and the largest ΔE is 0.236. For terrain, the highest values simulated for a black background are 0.852 for ΔE and 0.025 for C_p . For a more realistic gray terrain background the maximum values are 0.017 for C_p and 0.618 for ΔE .

Regional Haze at San Jacinto Wilderness Area

For Class I areas more than 50 km from a project, a regional haze analysis is required. CALPUFF modeling of regional haze impacts was conducted with the maximum short-term emission rates for the combustion turbines and the cooling tower stacks. Rather than use the Escondido meteorological data for this analysis, a more regionally representative five-year data set was used in accordance with FLM guidance (IWAQM, 1998). The CALPUFF model was run using meteorological data from Miramar NAS for 1986 through 1990.

Table 5.2-18 Level-3 Worst-Case PLUVUE II Modeling Results

Month	Time	Observer	Sky C _p	Background Δ E	White Terrain C _p	Background Δ E	Gray Terrain C _p	BackgroundΔ E	Black Terrain C _p	Background Δ E
January	AM	East	-0.003	0.114	-0.003	0.096	0.001	0.027	0.004	0.098
		West	-0.002	0.097	-0.002	0.076	0.003	0.115	0.008	0.224
	PM	East	-0.002	0.08	-0.002	0.087	0.007	0.215	0.012	0.364
		West	-0.003	0.117	-0.002	0.074	0.002	0.051	0.007	0.162
February	AM	East	-0.001	0.059	-0.001	0.047	0.001	0.021	0.004	0.088
		West	-0.006	0.228	-0.003	0.126	0.001	0.047	0.008	0.197
	PM	East	-0.001	0.095	0.003	0.15	0.009	0.339	0.003	0.015
		West	-0.006	0.215	-0.003	0.131	0.001	0.062	0.005	0.116
March	AM	East	-0.002	0.083	-0.002	0.071	0.001	0.022	0.005	0.108
		West	-0.002	0.102	-0.002	0.066	0.005	0.156	0.009	0.275
	PM	East	0.003	0.169	0.008	0.338	0.017	0.618	0.025	0.852
		West	-0.004	0.129	-0.002	0.092	0.001	0.032	0.005	0.11
April	AM	East	-0.002	0.076	-0.002	0.066	0.001	0.035	0.006	0.131
		West	-0.002	0.098	-0.001	0.055	0.004	0.137	0.01	0.252
	PM	East	-0.001	0.026	-0.001	0.025	0.002	0.051	0.005	0.125
		West	-0.004	0.129	-0.002	0.086	0.003	0.074	0.01	0.231
May	AM	East	-0.001	0.075	-0.002	0.064	0.002	0.05	0.007	0.163
		West	-0.001	0.087	-0.001	0.04	0.004	0.124	0.01	0.263
June	AM	East	-0.001	0.072	-0.002	0.066	0.001	0.029	0.005	0.116
		West	-0.002	0.15	-0.001	0.07	0.006	0.204	0.014	0.755
July	AM	East	-0.001	0.08	-0.002	0.072	0.001	0.039	0.006	0.14
		West	-0.001	0.113	0.001	0.072	0.006	0.21	0.013	0.374

5.2 Air Quality

Table 5.2-18 Level-3 Worst-Case PLUVUE II Modeling Results (cont'd)

Month	Time	Observer	Sky C _p	Background Δ E	White Terrain C _p	Background Δ E	Gray Terrain C _p	BackgroundΔ E	Black Terrain C _p	Background Δ E
August	AM	East	-0.001	0.075	-0.002	0.064	0.002	0.042	0.006	0.147
		West	-0.001	0.086	-0.001	0.041	0.004	0.13	0.01	0.253
September	AM	East	-0.003	0.138	-0.003	0.108	0.001	0.039	0.008	0.175
		West	-0.001	0.086	0.003	0.123	0.008	0.293	0.015	0.453
	PM	East	-0.002	0.08	-0.002	0.068	0.003	0.092	0.008	0.202
		West	-0.002	0.068	-0.001	0.055	0.001	0.036	0.005	0.122
October	AM	East	-0.002	0.085	-0.002	0.067	0.001	0.028	0.005	0.115
		West	-0.004	0.156	-0.003	0.105	0.002	0.054	0.009	0.207
	PM	East	-0.002	0.075	-0.003	0.148	0.01	0.366	0.018	0.576
		West	-0.007	0.236	-0.004	0.153	0.002	0.043	0.008	0.185
November	AM	East	-0.002	0.073	-0.002	0.06	0.001	0.021	0.004	0.092
		West	-0.006	0.212	-0.003	0.127	0.001	0.04	0.008	0.19
	PM	East	-0.004	0.14	-0.003	0.107	0.008	0.246	0.015	0.419
		West	-0.002	0.09	-0.002	0.068	0.001	0.02	0.004	0.099
December	AM	East	-0.002	0.079	-0.002	0.06	0.001	0.025	0.004	0.101
		West	-0.005	0.186	-0.003	0.12	0.001	0.04	0.007	0.168
	PM	East	-0.002	0.059	-0.002	0.064	0.004	0.131	0.009	0.248
		West	-0.005	0.195	-0.003	0.102	0.002	0.045	0.007	0.166

The results of the regional haze analysis are summarized in Table 5.2-19. As shown in the table, the maximum extinction change from the background never exceeds five percent. A five percent change in extinction coefficient is generally considered the lowest perceptible change, and is used as a significance threshold for visibility impacts. Thus, the Palomar project will not have an adverse regional haze impact, and no further modeling is necessary.

Acid Deposition

Based on information presented on the USFS website (www.fs.fed.us updated April 7, 2000), both Agua Tibia and San Jacinto Wilderness Areas have an AQRV associated with aquatic resources. NO_x and SO₂ emissions can affect aquatic resources through nitrogen and sulfur deposition. Acid neutralizing capacity (ANC), or alkalinity levels, can be used to measure a water body's ability to absorb nitrogen and sulfur deposition and withstand acidification. Several factors influence ANC, such as bedrock geology, the degree of soil weathering, watershed size and hydraulic detention. The higher the ANC the more resistant the water is to acidification. If nitrogen and sulfur deposition exceeds the ANC or the buffering capacity of a water body, then the ANC is diminished, pH drops, and acidification may occur.

Table 5.2-19 Maximum 24-Hour Average Regional Haze Impacts on San Jacinto Wilderness Area

Model Year	Maximum Extinction Change from Background (%)	Number of Days Maximum Change from Background is > 5%
1986	2.61	0
1987	2.21	0
1988	3.02	0
1989	3.19	0
1990	2.77	0

Another potential impact associated with nitrogen deposition is increased algae and plant growth due to the added nitrogen. In some cases, the increased growth leads to eutrophication of the water body, where introduced nitrogen acts as fertilizer and causes algae blooms. After dense algal mats cover a water body surface, subsurface algae die and cause oxygen deprivation during decay. This deprivation can lead to stressed aquatic resources and potential fish kills.

The CALPUFF model is generally used to determine the potential for impacts from acid deposition in Class I areas. CALPUFF screening modeling provided upper limit

estimates of annual (wet and dry) deposition of sulfur and nitrogen compounds (computed as kilograms per hectare per year (kg/ha/yr)) associated with Palomar Energy Project emissions of SO₂ and NO_x. Table 5.2-20 summarizes the maximum modeled annual sulfur and nitrogen deposition for the Agua Tibia and San Jacinto Wilderness Areas.

Table 5.2-20 Annual Deposition of Sulfur and Nitrogen at Agua Tibia and San Jacinto Wilderness Areas

Class I Area	Species	Annual Deposition (kg/ha/yr)
Agua Tibia	Sulfur	0.0013
	Nitrogen	0.0014
San Jacinto	Sulfur	0.0012
	Nitrogen	0.0013

No regulatory thresholds for acid deposition have been established for the Class I Areas. However, it is noteworthy that the modeled acid deposition impacts are more than two orders of magnitude below the minimum detectable limit for wet deposition (0.5 kg/ha/yr), and more than an order of magnitude below the conservative USFS significance threshold of 0.05 kg/ha/yr. Furthermore, the values for nitrogen are below the Deposition Analysis Threshold (DAT) of 0.005 kg/ha/yr being developed for Western Class I areas (FLAG, 2001). The DAT is a proposed value and should not be considered as an adverse impact threshold (McCorison, 2001). A DAT for sulfur has not yet been developed. Since increased nitrogen and sulfur deposition due to the proposed project will be insignificant, impacts to stream and river ANC and pH, and therefore acidification and/or eutrophication, are not likely to occur.

Vegetation

In order to define AQRVs and to provide for effective impact assessment methods for AQRVs, the USFS held workshops in 1990 (USFS, 1992). The guidelines developed during this workshop, as well information posted on the USFS website have been used in preparing the assessments presented below for the Agua Tibia and the San Jacinto Wilderness Areas with respect to potential air quality impacts to vegetation in these areas.

The two wilderness areas contain vegetative ecosystems as identified by the FLM (USFS, 1992). These ecosystems are shown in Table 5.2-21. For each ecosystem, sensitive species or groups of species have been designated to represent potential impacts to vegetation species in the ecosystem. The vegetation species of concern for the designated

wilderness areas are given in Table 5.2-22. These species are impacted primarily by ozone, but are also impacted by nitrogen and sulfur compounds. Sensitivity of several species is presented in Table 5.2-23 (USFS, 1992).

Table 5.2-21 Vegetative Ecosystems for Nearby Class I Wilderness Areas

Agua Tibia Wilderness	San Jacinto Wilderness
Bigcone Douglas Fir	Mixed Conifer and Hardwood Forest
Chaparral	Montane Chaparral
Mixed Conifer	Montane Riparian Forest
Oak Woodland	
Riparian	

Table 5.2-22 Sensitive Vegetative Species for Nearby Class I Wilderness Areas

Agua Tibia Wilderness	San Jacinto Wilderness
Lichens	Ponderosa Pine
Herbaceous Plants	Jeffrey Pine
Huckleberry Oak	Coulter Pine
Ponderosa Pine	Black Oak
Jeffrey Pine	Coffeeberry
White Fir	Gooseberry
California Black Oak	Great Basin Sagebrush
Aspen	Ceanothus
Alders	Willow
Cottonwoods	White Alder
Sedges	Black Cottonwood
Big Cone Douglas Fir	Conifers
Douglas Fir	Limber Pine
Western White Pine	Lodge Pole Pine
Santa Lucia Fir	Western White Pine
Sugar Pine	Herbaceous Plants
Incense Cedar	Shrubs

Exposure to ozone can produce several quantifiable effects on vegetation, including visible damage. Sensitivity to ozone and other stresses varies because of differences in

5.2 Air Quality

uptake and genetic factors. Four condition classes have been established with respect to ozone effects on trees; they are presented in Table 5.2-24.

Table 5.2-23 Sensitivity of Tree Species to Pollution

Sensitive Receptor	Sensitivity ¹		
	Ozone	Sulfur	Nitrogen
Ponderosa Pine	H	H	H
Jeffrey Pine	H	H	H
White Fir	M	H	H
Incense Cedar	L	---	---
California Black Oak	M	---	---
Douglas Fir	M	H	H
Big Cone Douglas Fir	L	---	---
Western White Pine	L-M	---	---
Lodge Pole Pine	M	H	H
Limber Pine	M	---	---
Huckleberry Oak	L	---	---
Aspen	H	---	---
Alders	M	---	---
Sugar Pine	---	---	---
White Bark Pine	---	---	---
Fox Tail Pine	---	---	---
Pacific Silver Fir	---	---	---
Mountain Hemlock	---	---	---
Red Fir	---	---	---
Digger Pine	---	---	---
Cottonwoods	---	---	---
Junipers	---	---	---
Coast Redwood	---	---	---
Pinyon Pine	---	---	---
Santa Lucia Fir	---	---	---

1. Ratings are given in USFS (1992). Sensitivity to sulfur and nitrogen are based primarily on experimental exposures to acidic fog, SO₂ and NO₂. Sensitivity ratings are: high (H), moderate (M) and low (L). Dashes indicate insufficient information to rate sensitivity.

There are few data on the effect of sulfur compounds on vegetation, and there is a wide range of sensitivities to sulfur compounds. In order to protect sensitive species, the USFS (1992) recommends that short-term maximum levels should not exceed 40-50 ppb, and annual average concentrations should not exceed 8-12 ppb. Given the very low level of sulfur dioxide emissions from the proposed project, there will not be any measurable impact in either the Agua Tibia or the San Jacinto Wilderness Areas.

Table 5.2-24 Condition Classes for Ozone Impacts on Trees

Class	Ozone Concentration 7-Hour Growing Season Mean (ppb)
No Injury	<60
Slight Injury	61-70
Moderate Injury	71-90
Severe Injury	>90

Source: USFS, 1992.

There are also few data related to the impacts of nitrogen dioxide on vegetation. However, some general guidelines can be established, based on available research. These guidelines are presented in Table 5.2-25. Since no data are available to quantify existing ambient levels of nitrogen dioxide in the Agua Tibia Wilderness Area, a receptor was included in the dispersion modeling corresponding to the point along the Agua Tibia Wilderness Area boundary closest to the proposed project. The modeling predicts a one-hour and annual average nitrogen dioxide increase of 1.2 and 0.03 $\mu\text{g}/\text{m}^3$ (0.63 and 0.02 ppb), respectively, at that receptor. Given these levels of concentration increases, the maximum 24-hour increase is not expected to exceed the concentrations thresholds listed in Table 5.2-25, and therefore no adverse impacts are expected. A similar analysis was performed for the San Jacinto Wilderness Area, which is located further away from the proposed project site. The modeling predicted an annual average nitrogen dioxide increase of 0.010 $\mu\text{g}/\text{m}^3$ (0.005 ppb). Potential impacts in the San Jacinto Wilderness Area are also expected to be insignificant.

Table 5.2-25 Condition Classes for NO₂ Impacts on Vegetation

Class	NO₂ Concentration 24-Hour Annual Mean (ppb)
No Injury	<15
Potential Injury	15-50
Severe Injury	>50

Source: USFS, 1992.

Lichens are also sensitive receptors for air pollutants. Lichens grow slowly and can live for centuries, and serve as an indicator of the cumulative effects of exposure to air pollution. Table 5.2-26 presents sensitivity guidelines suggested by the Forest Service (1992). There are no ambient monitoring data available for Agua Tibia Wilderness Area

5.2 Air Quality

or San Jacinto Wilderness Area. However, given the very minor contribution from the proposed project, the project will not result in any significant impacts.

Table 5.2-26 Condition Classes for Lichens

Pollutant	Sensitivity Class			
	Very Sensitive	Sensitive	Tolerant	Very Tolerant
Ozone (ppb) ¹	≤20	21-40	41-70	>70
Sulfur (kg/ha/yr)	≤1.5	1.5-2.5	2.6-3.5	>3.5
Nitrogen (kg/ha/yr)	≤2.5	2.6-5.0	5.1-7.0	>7.0

¹ Ozone concentration is the 7-hour mean for May-October.

5.2.1.5 Other Related Analyses

EPA, PSD and SDAPCD regulations require that additional analyses be performed for major stationary sources. The additional analyses required for the Palomar Energy Project are described in this section.

Vegetation and Soils

The highest predicted ambient air quality impacts from the Palomar Energy Project (as determined from dispersion modeling discussed in previous sections) will be in the high terrain areas to the west of the project site. To a lesser extent, air quality impacts also will occur at less elevated areas close to the site. The dominant plant communities represented in the vicinity of the project site and within the predicted highest areas of air quality impacts include the following:

- Coastal Sage Scrub
- Coast Live Oak Woodland

To a lesser extent, the following communities and land uses also are distributed in the vicinity of the project site:

- Freshwater Marsh
- Riparian Forest
- Riparian Scrub
- Grassland

Several plants and animals considered “sensitive” species are distributed throughout these areas. Reasons for the sensitive designation vary, including both natural rare occurrences and population decline. Others are sensitive based on declining habitat availability.

There are few data on the effects of sulfur compounds on vegetation and there is a wide range of sensitivities to sulfur compounds. There is limited information regarding the direct effects of air pollution on animals at the concentrations expected in the vicinity of the project. For mammals, it seems plausible (however still speculative) that the effects of air pollution on respiratory systems may be similar to that of humans. For non-mammalian species, such as birds, reptiles, amphibians, fish and invertebrates, the effects are entirely speculative. For this reason, the discussion of ambient air quality impacts will focus on the primary producers of food and energy in an ecological system: the plants. It stands to reason that plant communities may impact animal populations via food sources.

Air quality impacts on plants are due to external factors such as regional and local emissions and meteorology, specific genetic susceptibilities of individual species, and natural variations between individuals of the same species. Impacts may be direct or indirect. Direct impacts could include the effects of ozone on leaf and needle tissues; indirect impacts could include a change in soil pH that leads to increased stress on a plant, making it more susceptible to plant pathogens, or unable to photosynthesize vital nutrients efficiently.

Of the criteria pollutants, ozone is considered to be the most phytotoxic, or toxic to plant leaves. During the exposure of a plant to ozone, stomata on the underside of plant leaves open to allow respiration and an exchange of gases. Normally, plants take in carbon dioxide and release oxygen. In an ozone-rich atmosphere, ozone may be taken up in the stomata. Visible evidence of injury includes visible white flecks on the surface of leaves exposed to sunlight, and coloration changes such as purpling in the sunlight-exposed leafy tissue. Thus, affected plants have reduced photosynthesis and therefore less plant growth. With the reduced photosynthesis function, the plant also exports less carbohydrate from the leaves to the other sensitive structures of the plants, particularly the roots. Therefore, the greatest effects of ozone exposure to plants are in the leaves and the root system. Prolonged exposure to ozone can lead to leaf necrosis, or death of the affected leaves, as evidenced by chlorosis (or yellowing) of the leafy tissue. Ozone exposure leads to earlier senescence of the leaves, shortening the life span of the exposed leaves. Ozone forms at distances away from the source of precursor emissions and is not directly emitted from combustion equipment. Ozone formation due to the Palomar Energy Project emissions of NO_x and VOCs will be minimized through the combustion of clean-burning natural gas fuel, the use of the NO_x emission control technology (SCR),

and an oxidation catalyst that reduces VOC emissions in addition to reducing CO emissions.

Nitrogen dioxide emitted from fossil fuel combustion may undergo reactions in the atmosphere to form nitric acid (HNO_3), which may dissociate into H^+ and NO_3^- ions. The presence of H^+ lowers the pH of water molecules, either in the atmosphere such as in acid rain or fog, or as particulate soil deposition. Similarly, sulfur dioxide may undergo reactions in the atmosphere and form sulfate (SO_4) and sulfuric acid (H_2SO_4). The sulfuric acid adds H^+ ions to the water, changing the pH to more acidic levels. Often the acidity of acid fog is greater than the acidity of acid rain because of the greater surface exposure to H^+ ions in the atmosphere for the same volume of water. It is rare that exposure to acid deposition can cause direct injury to plant leaves or needles. Acidic deposition may penetrate through cracks in the cuticle, but only if the pH of the deposit is quite low. Such acidic deposition levels are generally not found in southern California.

There is increasing evidence that significant acidic deposition may alter the pH of soils and affect soil chemistry, including that the beneficial mycorrhizal and ectomycorrhizal plant root associations and the corresponding root nutrient uptake of the plant may be adversely affected. The degree of adverse effect varies and is influenced by several factors, including individual susceptibility of plants, their mycorrhizae, the soil composition, meteorological considerations, etc. The general weakening of the plant function from inhibited nutrient uptake in the roots may inhibit its responses to adverse affects from potential pathogens and/or other possible environmental stresses through the growth of vegetative and reproductive structures.

Based on the efficient combustion of natural gas fuel that meets low sulfur standards, sulfuric deposition impacts to plant communities are anticipated to be insignificant for the Palomar Energy Project. Similarly, because of the low NO_x technologies proposed for the project, nitrogen deposition impacts are not anticipated to be significant.

Growth Analysis

PSD requires an assessment of the secondary impacts from applicable projects. However, there is no associated growth expected from the Palomar Energy Project construction phase employment because of the large existing construction work force in the region. Additionally, no long-term growth (i.e., general commercial, residential, industrial or other secondary growth in the area) is expected during operations due to the small labor force (20 full-time staff) that will be required to operate this plant. Therefore, no analysis of secondary impacts from associated growth is needed.

Alternatives Analysis

SDAPCD Rule 20.3(e)(2) requires that an Applicant for a new major stationary source that is required to satisfy the LAER requirements of Rule 20.3(d)(1) or the offset requirements of Rule 20.3(d)(5) conduct an alternatives analysis. Section 3 provides an alternatives analysis for the Palomar Energy Project, including environmental issues. This analysis satisfies the requirements of SDAPCD Rule 20.3(e)(2).

5.2.4 Mitigation Measures

5.2.4.1 Construction Mitigation

Construction emissions include fugitive dust and exhaust from equipment, including diesel particulates. Fugitive dust emissions will result primarily from construction activities and vehicle traffic associated with construction. Fugitive dust control regulations require fugitive dust control for PM₁₀ for construction, demolition, excavation, handling and storage of bulk materials and vehicle parking, shipping, fueling and transfer areas. Construction equipment emissions may be mitigated in a variety of ways such as engine tuning, use of ultra-low-sulfur fuel, and use of catalytic diesel particulate filters, where suitable. Prior to the commencement of project construction the following construction plans shall be submitted to the CEC for approval:

- Onsite Fugitive Dust Control Plan;
- Vehicle Track-out Control Plan; and
- Diesel Construction Equipment Mitigation Plan

5.2.4.2 Offsets

SDAPCD Rule 20.3(d)(8) requires major new stationary sources of NO_x and VOC to offset these emissions. Since the NO_x emissions from the project are greater than 50 tons per year, offsets are required for NO_x emissions. Palomar Energy, LLC will offset the Palomar facility NO_x PTE of 124 tons per year with NO_x emission reduction credits (ERCs) and/or with an interpollutant trade of VOC ERCs as allowed by SDAPCD Rule 20.3(d)(5)(vi). NO_x ERCs will be provided at the ratio of 1.2 to 1.0. Alternatively, VOC ERCs will be provided at an additional ratio of 2.0 to 1.0, or a total ratio of 2.4 tons of VOC ERC for each ton of NO_x emissions. Since the Palomar facility's PTE of VOC is less than 50 tons per year, additional ERCs for the VOC emissions are not required. The Applicant's offset plan is summarized in a separate filing that will be submitted concurrent with this AFC submittal.

Palomar is not seeking to waive the AQIA requirement for PM₁₀ and has demonstrated that the proposed project is not expected to cause or contribute to a violation of the

California AAQS (Rule 20.3(d)(2)(i)). Therefore, PM₁₀ offsets are not required. Since the area is attainment for CO and SO₂, offsets for these pollutants are not required.

5.2.5 Significant Unavoidable Adverse Impacts

No significant unavoidable adverse impacts on air quality are anticipated as a result of project construction and operation.

5.2.6 Cumulative Impacts

Although project impacts are modeled to be below the federal SILs, the CEC requires applicants to perform a cumulative analysis. Therefore, a cumulative analysis was conducted for the Palomar project and offsite emission sources not represented in the background air quality data. A list of projects to be included in the cumulative analysis was requested from the SDAPCD, and the only offsite emission sources identified by them (SDAPCD, 2001) were the CalPeak and RAMCO projects. The two projects are both <50 MW natural gas-fueled power plants being developed near the Palomar project site. The focus of the cumulative analysis of the three power plants (Palomar, CalPeak, and RAMCO projects) is concurrent operations of all three facilities, because both of the small power plants will be in operation before the Palomar project begins construction.

The cumulative analysis also addresses the air quality impacts of the Palomar project together with the overall Escondido Research and Technology (ERTC) industrial park within which the Palomar site is located. In order to provide data requested by the CEC Staff, the cumulative analysis delineates between effects associated with Planning Area 1 (PA 1) of the ERTC industrial park (the Palomar project site) versus the remainder of the industrial park.

Emissions and source parameters for the CalPeak and RAMCO projects were obtained from the SDAPCD. The cumulative operations phase analysis was conducted using AERMOD in the West Hills complex terrain receptor domain, since the maximum impacts due to the Palomar project operations occurred in this area. The ISCST3 model was also used in the analysis in the simple terrain modeling domain to estimate cumulative impacts within the vicinity of all three facilities. Model-predicted impacts for the three power plant sources included in the cumulative analysis were added to the background concentrations and compared against the AAQS. The results of this cumulative analysis are provided in Table 5.2-27. The maximum cumulative impacts, except for the 1-hour NO₂ concentrations, occurred in the complex terrain receptors approximately 2 miles (3.2 kilometers) west of the Palomar site. The maximum cumulative 1-hour NO₂ concentration was predicted to occur in the area adjacent to the CalPeak facility. It should be noted that there was no contribution from the Palomar project to the maximum cumulative 1-hour NO₂ concentration.

Table 5.2-27 Maximum Cumulative Impacts During Palomar Operations

Pollutant	Averaging	Cumulative	Background ²	Total Predicted	Ambient
-----------	-----------	------------	-------------------------	-----------------	---------

	Period	Maximum Modeled Impact ($\mu\text{g}/\text{m}^3$) ¹	($\mu\text{g}/\text{m}^3$)	Concentration ³ ($\mu\text{g}/\text{m}^3$)	Air Quality Standard ⁴
NO ₂	1-hour	33.4 ⁵	191	224	470
	Annual	1.0	44	45	100
CO	1-hour	33.3	11,870	11,900	23,000
	8-hour	15.3	6,123	6,140	10,000
PM ₁₀	24-hour	5.0	65	70	50
	Annual	0.9	28.5	29.4	30

1 Includes the Palomar, CalPeak, and RAMCO facilities.

2 Background air quality data for NO₂, CO, and PM₁₀ obtained from the SDAPCD Escondido monitoring station during the period 1998-2000.

3 Concentration totals rounded to three or fewer significant figures.

4 Most stringent of federal or state ambient air quality standard for each pollutant and averaging period.

5 Assumes 100 percent conversion of NO_x to NO₂.

The total cumulative impacts due to all sources are below the AAQS except for 24-hour PM₁₀. As discussed in Section 5.2.3.2, adding the total predicted 24-hour PM₁₀ impacts to the high background days results in a concentration that exceeds the California AAQS because the background levels have already exceeded the standard (once in 1998, once in 1999, and twice in 2000, with annual average concentrations remaining relatively constant throughout this three year period). However, the two other power plant projects contribute less than 0.3 $\mu\text{g}/\text{m}^3$ to this concentration, which is located on the high terrain west of the project. As stated previously, this location is not expected to have the same high background level as that observed at the downtown Escondido monitoring station, and hence a new violation due to cumulative impacts is considered unlikely.

Overall ERTC Industrial Park Construction

Overall construction of the ERTC industrial park will extend over a several year period from 2002 to 2008. It will include an initial site preparation phase that will last approximately nine months and involve extensive earthmoving to prepare building pads in each of eight planning areas (including PA 1, the Palomar site) and to develop roadways and other infrastructure. Subsequent phases of ERTC industrial park construction will involve the development primarily of one and two story concrete tilt-up industrial buildings and low-rise office buildings in the various planning areas. The cumulative criteria pollutant emissions for industrial park grading and Palomar project construction are given in Appendix E in Tables E.6-41 through E.6-45. The tables cover the site preparation work that precedes power plant construction, and the 21 months when both power plant construction and ERTC industrial park construction are ongoing concurrently.

The City of Escondido is the Lead Agency for the CEQA review of the Specific Plan for the ERTC Specific Planning Area and the ERTC industrial park. The CEQA process will address the air quality impacts and, as appropriate, mitigation measures for industrial park development. Mitigation measures that often are considered for construction projects that involve heavy equipment include proper equipment maintenance, retrofitting of heavy construction equipment that will be operating for extended periods with commercially available air pollution control devices where feasible, and use of low-sulfur diesel fuel where feasible.

Planning Area 1 Construction Phase Earthwork

Estimated emissions from ERTC industrial park earthwork (excavation and grading) involved in site preparation for PA 1 (the Palomar site) are given in Appendix E in Tables E.6-1 through E.6-5. The PA 1 grading emissions are summarized in Table 5.2-28. This site preparation work will be performed prior to other ERTC industrial park construction activities and prior to Palomar facility construction activities. Table 5.2-29 shows the impacts on ambient air quality at the PA 1 fenceline of the emissions from the PA 1 earthwork. These impacts are based on dispersion modeling using the ISCST3 model and follow the methods outlined in the modeling protocol (Appendix E.4). Because the ERTC industrial park earthwork activities involving PA 1 will last only 70 days, no annual average impacts were estimated.

Table 5.2-28 Planning Area 1 Earthwork Emissions

Pollutant	Phase 1 (10 days) (lb/day)	Phase 2 (60 days) (lb/day)
NO _x	786	497
CO	967	611
SO ₂	18	12
PM ₁₀	91	102

The maximum modeled impacts at the PA 1 fenceline due to PA 1 earthwork are at a location where people neither reside or work. Therefore, no actual long-term exposure occurs at these locations. Table 5.2-30 provides the PA 1 earthwork impacts at the nearest residential and worker locations. The PM₁₀ concentrations in Table 5.2-30 do not include the assumed worst-case background 24-hour PM₁₀ concentration of 65 µg/m³, a value already exceeding the California AAQS. The 1-hour NO₂ concentrations were computed using the ozone limiting method and include the background NO₂ concentration.

Table 5.2-29 Maximum PA 1 Earthwork Ambient Air Quality Impacts

Pollutant	Averaging Period	Maximum Estimated Impact ($\mu\text{g}/\text{m}^3$)	Background¹ ($\mu\text{g}/\text{m}^3$)	Total Predicted Concentration² ($\mu\text{g}/\text{m}^3$)	Ambient Air Quality Standard³ ($\mu\text{g}/\text{m}^3$)
NO ₂	1-hour	729 ⁴	79 ⁴	808 ⁴	470
CO	1-hour	8,910	11,900	20,800	23,000
	8-hour	3,410	6,120	9,530	10,000
SO ₂	1-hour ⁵	168	397	565	655
	24-hour ⁶	24.6	53	78	105
PM ₁₀	24-hour ⁶	154	65	219	50

- 1 Background air quality data obtained from the Escondido monitoring station, except SO₂, which is from the Chula Vista station
- 2 Concentration totals rounded to three or fewer significant figures.
- 3 Most stringent of federal or state ambient air quality standard for each pollutant and averaging period
- 4 Maximum 1-hour NO₂ concentration estimated using the Ozone Limiting Method. The maximum modeled NO₂ concentration and the background NO₂ concentration are for the hour yielding the highest total 1-hour NO₂ concentration.
- 5 Compliance with the 1-hour California AAQS ensures compliance with the less stringent 3-hour National AAQS

The maximum offsite NO₂ concentrations for both offsite worker and residential exposure are below the 1-hour California AAQS. The offsite PM₁₀ concentration, without background, is below the National AAQS at the maximum residential receptor, but is above the National AAQS at the highest offsite worker receptor. The modeled offsite worker exposure is at the exterior of the building and does not necessarily reflect a potential exposure for a worker inside the building during an eight hour work day.

The grading activities associated with PA 1 will occur prior to construction of the power plant. Since the National AAQS and California AAQS in question are short-term averaging periods (i.e., one day or less), emissions associated with PA 1 earthwork will not have a cumulative effect due to the construction or operation of the Palomar power plant, as those activities will not overlap with grading of the ERTC industrial park.

Overall Industrial Park Operations

Although specific tenants for the ERTC industrial park have not yet been identified, light industrial and commercial office activities would not be expected to represent significant stationary sources of air pollutant emissions. There would be a substantial working population at the industrial park as its various phases of development occur, which would involve substantial motor vehicle traffic and associated air emissions. Given that the

5.2 Air Quality

ERTC industrial park would not represent a major increment of stationary emissions, and the Palomar project would involve a very small operational work force (approximately 20 people), no considerable cumulative air quality impacts are expected during operations of the ERTC industrial park and Palomar project.

Impacts and mitigations related to PA 1 grading are expected to be addressed in the City of Escondido's EIR currently being prepared for the ERTC industrial park project.

Table 5.2-30 Maximum Potential PA I Earthwork Offsite Worker and Residential Exposures

Pollutant	Averaging Period	Exposure Type		Applicable Standard
		Residential	Offsite Worker	
NO ₂	1-hour	312	434	470 ¹
PM ₁₀	24-hour	44	64	50 ²

1 California Ambient Air Quality Standard.

2 National Ambient Air Quality Standard.

5.2.7 LORS Compliance

This section provides a description of the laws, regulations, and standards that are or may be applicable to the Palomar Energy Project. Applicable air quality rules and regulations for this project are promulgated by and enforced by federal and local agencies. Many of these regulations have been delegated from the federal level to the local air agency level. Regulatory oversight authority for air quality matters rests at the local level with the SDAPCD and at the federal level with EPA Region IX. The Palomar facility will be classified as a major source under Title V of the 1990 Clean Air Act (CAA) Amendments.

A discussion of the applicable federal, state and SDAPCD air quality rules and regulations is provided below.

5.2.7.1 Federal Regulations

The applicable federal regulations are provided and summarized in Table 5.2-31.

Table 5.2-31 Federal Regulatory Requirements and Compliance

Regulation	Requirements	Compliance Demonstrated
40 CFR 50 National Primary and Secondary Ambient Air Quality Standards	National primary ambient air quality standards define levels of air quality which the Administrator judges are necessary, with an adequate margin of safety, to protect the public health. National secondary ambient air quality standards define levels of air quality which the Administrator judges necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.	An air quality impact analysis has been prepared which demonstrates the Palomar Energy Project will not cause or contribute to a violation of the National AAQS (see Section 5.2.3).
40 CFR 52.21 Prevention of Significant Deterioration (PSD)	<ul style="list-style-type: none"> • Best Available Control Technology (BACT) • Air quality impact analysis (AQIA) • Additional impacts analyses. 	<ul style="list-style-type: none"> • A BACT analysis for attainment pollutants PM₁₀, NO₂, SO₂ and CO has been provided in Section 5.2.2. • An air quality impact analysis has been prepared which demonstrates the proposed project will not cause or contribute to a violation of the National AAQS (see Section 5.2.3). • Additional impacts analyses have been prepared which demonstrate that the proposed project will not cause significant additional impacts (see Section 5.2.3).

Table 5.2-31 Federal Regulatory Requirements and Compliance (cont'd)

5.2 Air Quality

Regulation	Requirements	Compliance Demonstrated
<p>40 CFR 60 Subpart A New Source Performance Standards</p> <p>40 CFR 60 Subpart A</p>	<p>For affected facilities under Subpart Db and GG:</p> <ul style="list-style-type: none"> • Notification of: construction, anticipated date of initial startup, actual date of initial startup, and any physical change or operational change. [60.7(a)] • Maintaining records of any startup, shutdown, or malfunction. [60.7(b)] • Reporting of excess emissions and monitoring system performance. [60.7(c, d)] • Frequency of reporting can be reduced from quarterly to semiannual depending on the conditions met. [60.7(e)] • All data required by this part, including Subpart A, Db and GG, shall be retained for at least two years. [60.7(f)] • Performance test and reporting of results shall be within 60 days of achieving maximum production and no later than 180 days of startup. [60.8(a)] • Testing shall be conducted in accordance with applicable subpart under conditions specified by the Administrator. [60.8(b, c)] • Provide Administrator at least 30 days prior notice of performance test. [60.8(d)] • Provide for performance testing facilities. [60.8(e)] • Each performance test shall consist of three separate runs. [60.8(f)] • Compliance with the applicable opacity standard shall be conducted in accordance with the provisions of this section. [60.11] • Continuous monitoring systems and monitoring devices shall be used in accordance with the provisions of this section, except the provisions for opacity monitoring do not apply. [60.13] • General notification and reporting requirements shall be done in accordance with the provisions of this section. [60.19] 	<ul style="list-style-type: none"> • Notifications, recordkeeping and reporting will be performed in accordance with the applicable requirements. • The required performance tests will be conducted in a timely manner and in accordance with the required procedures and methods. • Demonstration of compliance and operation of monitoring systems and devices will be done in accordance with the applicable provisions.

Table 5.2-31 Federal Regulatory Requirements and Compliance (cont'd)

Regulation (cont.)	Requirements	Compliance Demonstrated
40 CFR 60 Subpart Db New Source Performance Standards	<p>For the HRSG duct burners:</p> <ul style="list-style-type: none"> • NO_x emissions shall not exceed 0.2 lb per million British thermal units heat input on a 30-day rolling average. [60.44b(a)(1)] • Affected facilities shall be equipped with a continuous monitoring system or CEMS for NO_x and O₂. [60.48b(b)]. The system shall follow the data requirements of this section. • Conduct initial performance test. [60.46b(e)] • Reporting of emissions on a semiannual basis to the Administrator. [60.49b] 	<ul style="list-style-type: none"> • HRSG duct burners will be exclusively fired using natural gas. The performance data based on natural gas indicates that NO_x emissions will meet the applicable standard. • The stacks will be equipped with CEMS for monitoring NO_x and O₂ concentrations. • The performance test required in 60.8 will be completed following startup in accordance with the applicable methods specified in this subpart. • Reporting to the EPA Administrator will be performed in accordance with applicable requirements.

Table 5.2-31 Federal Regulatory Requirements and Compliance (cont'd)

Regulation	Requirements	Compliance Demonstrated
40 CFR 60 Subpart GG New Source Performance Standards	<p>For the CTGs:</p> <ul style="list-style-type: none"> • NO_x emissions shall not exceed 75 ppmvd (@15% O₂), times an upward correction for fuel bound nitrogen and thermal efficiency. [60.332(a)(1)] • SO₂ emissions shall not exceed 150 ppmvd (@15% O₂). [60.333(a)] • Fuel burned in the CTGs shall not contain sulfur in excess of 0.8 % by weight. [60.333(b)] • Fuel sulfur and nitrogen contents shall be monitored in accordance with the applicable requirements of this subpart. [60.334(b)] • Excess emissions shall be reported in accordance with the applicable requirements of this subpart and 60.7(c). [60.334(c)]. • Conduct initial performance test. [60.335(b)] • Evaluating compliance with the applicable standards shall be based on the methods specified in this subpart. [60.335] 	<ul style="list-style-type: none"> • CTGs will be equipped with BACT that exceeds the NO_x emission control requirements of this subpart. The performance data indicates that NO_x emissions will not exceed the applicable standard. • CTGs will be exclusively fired using natural gas and the sulfur content of natural gas is well below the applicable standard. The performance data indicates the SO₂ emissions will be well below the applicable standard. • The performance test required in 60.8, determining the nitrogen content, and computing the emissions will be completed following startup in accordance with the applicable methods specified in this subpart. An alternative sulfur monitoring schedule, as allowed by this subpart, is proposed.

Table 5.2-31 Federal Regulatory Requirements and Compliance (cont'd)

Regulation	Requirements	Compliance Demonstrated
40 CFR 61 Subpart M NESHAP for Asbestos	Requires notification when demolition occurs at the facility.	Palomar will provide notification when demolition is to occur at the facility.
40 CFR 63 Subpart YYYY MACT Standard for Gas Turbines	A MACT Standard for gas turbines is expected to be promulgated in May 2002.	Not expected to apply to the Palomar Energy Project.
40 CFR 64 Compliance Assurance Monitoring (CAM)	Requires a CAM Plan for each affected emissions unit and pollutant. The CAM Plan specifies the parameters to be monitored, the performance indicators to assure the control device is operating properly, and the corrective action to be taken should the operating conditions drift beyond the stated performance range.	Units are exempt since CEMS will be required under the Title IV program for NO _x and Title V for CO.
40 CFR 68 Risk Management Program (RMP)	Requires an RMP plan for each listed chemical stored and/or handled in quantities greater than the applicable threshold (i.e., 20,000 pounds for ammonia). The plan identifies the management programs in place or to be established to mitigate risk of a potential release, and evaluates the potential risk associated with a worst-case accidental release.	An RMP for aqueous ammonia will be prepared prior to startup, if required. The RMP will address the data elements required under 40 CFR 68.
40 CFR 70 Title V	Requires states or local agencies to develop comprehensive operating permit programs that cover "major" sources of air pollution.	A Title V application will be prepared for the proposed facility.
40 CFR 72 Permits Regulation	Regulates compliance with Acid Rain Program.	Phase II acid rain application will be prepared for the proposed facility.

Table 5.2-31 Federal Regulatory Requirements and Compliance (cont'd)

Regulation	Requirements	Compliance Demonstrated
40 CFR 73 Sulfur Dioxide Allowance System	Regulates sulfur dioxide allowances.	Compliance will be achieved by providing SO ₂ allowances as required by permit issued by SDAPCD.
40 CFR 75 Continuous Emission Monitoring	Requires continuous emission monitoring of applicable pollutants.	Compliance will be achieved by meting the requirements for NO _x CEMS

Prevention of Significant Deterioration (PSD)

The determination of whether PSD regulations are applicable is based on the attainment status of the area and the type and quantity of PSD-regulated pollutants that will be emitted. Since the area where the proposed project will be located is designated as federal attainment or unclassifiable for all criteria pollutants except ozone, PSD review will apply as discussed below.

For PSD purposes, a major stationary source is defined as either one of the sources identified in 40 CFR 52.21 and which has a potential to emit 100 tons or more per year of any regulated pollutant, or any other stationary source (not specifically identified in 40 CFR 52.21) which has the potential to emit 250 tons or more per year of a regulated pollutant. “Potential to emit (PTE)” has a special meaning in this situation, since it is determined on an annual basis after the application of air pollution control equipment, or any other federally enforceable restriction. Once it is determined that the emissions from the facility of a pollutant exceeds the PSD major source threshold, additional pollutants will be subject to PSD review if their PTE exceeds the PSD significant emission rates listed in Table 5.2-32.

Table 5.2-32 PSD Significant Emission Rates

Pollutant	Emission Rate (tons per year)
Carbon monoxide	100
Nitrogen oxides	40
Sulfur dioxide	40
Particulate Matter	25
Fine particulate matter (PM ₁₀)	15
Ozone	40 (as VOCs)
Lead	0.6
Fluorides	3
Sulfuric acid mist	7
Total reduced sulfur	10

Source: 40 CFR 52.21

By this definition, Palomar constitutes a major stationary source, as it falls within one of the 28 named source categories and will emit more than 100 tpy of at least one regulated pollutant, i.e., NO_x, PM₁₀, and CO. In addition, emissions of VOC will be greater than the applicable significance thresholds shown in Table 5.2-32. Therefore, the project is subject to

5.2 Air Quality

PSD pre-construction permitting review, in addition to other federal or state requirements. The various requirements of the PSD program are addressed in this application.

A BACT analysis has been provided for federal attainment pollutants PM₁₀, NO₂, SO₂ and CO. For the combustion turbines, BACT has been proposed in the form of DLN and SCR for NO_x emissions control to achieve an emission rate of 2.0 ppm @15% O₂, 3-hour average, the use of oxidation catalyst for CO emissions control to achieve an emission rate less than 4 ppm @15% O₂, 3-hour average and the exclusive firing of natural gas to limit PM₁₀ and SO₂ emissions.

An air quality impacts analysis has been prepared that demonstrates that: 1) proposed project will not cause or contribute to a violation of AAQS, 2) the project's ambient air quality impacts are less than the significant impact levels for all criteria pollutants for Class I areas, and 3) the air quality increments are not exceeded.

Additional impacts analyses have been prepared including growth, soils and vegetation and visibility impairment, which demonstrate that the project will not cause significant additional impacts.

New Source Performance Standards (NSPS)

The regulation of new sources, through the development of standards applicable to a specific category of sources, was a significant step taken by the 1970 CAA Amendments (P.L. 91-604). The Administrator was directed to prepare and publish a list of stationary source categories which, in the Administrator's judgement, cause or contribute significantly to air pollution and which may reasonably be anticipated to endanger public health. Further, the Administrator was to publish a proposed regulation establishing a Standard of Performance for any new source that fell into that category. The significant feature of the law is that it applies to all sources within a given category, regardless of its geographic location or the ambient air quality at that location. The standards define emission limitations that would be applicable to a particular source group.

The only NSPS determined to be applicable to emission units at the proposed facility are Subparts A, Db and GG. Subpart GG applies to gas turbines and includes emissions standards for NO_x and SO₂. However, since the proposed turbines will be gas-fired, and due to the stringent BACT requirements, emissions limits for this facility will be significantly lower than the Subpart GG standards.

Subpart Db applies to the duct burner portions of both gas turbines, which meet the definition of steam generating units firing greater than 100 million British thermal units per hour.

Palomar will comply with emission and fuel monitoring requirements of NSPS Subpart GG and Db, and monitoring plans will be submitted, as required. These regulations have been incorporated by reference in SDAPCD Regulation X.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

National Emission Standards for Hazardous Air Pollutants contain emissions standards related to hazardous air pollutants (HAP) for both new and existing sources. NESHAP promulgated before the CAA Amendments of 1990 are contained in 40 CFR 61, and are generally focused on a specific pollutant, e.g., asbestos. The 1990 CAA Amendments greatly changed the way NESHAP were adopted, and these NESHAP generally focus on source categories. Post-1990 NESHAP are found in 40 CFR 63 and are known as Maximum Achievable Control Technology (MACT) Standards. These regulations have been incorporated by reference in SDAPCD Regulation XI.

The only pre-1990 NESHAP that is applicable to the Palomar facility is 40 CFR 61 Subpart M. Even though no asbestos will be used in the construction of the facilities, this regulation requires notification when demolition occurs at the facility.

There currently are no MACT standards (40 CFR 63) applicable to the proposed project. A MACT standard for gas turbines is scheduled to be developed sometime in 2002. If the MACT standard is applicable once promulgated, then Palomar Energy, LLC will comply. The Palomar Energy Project will not be a major source of HAP, so the standard is not expected to apply. Furthermore, the Palomar facility will install an oxidation catalyst, which is the most likely control technology to be required by the MACT standard.

Compliance Assurance Monitoring

On October 22, 1997, EPA promulgated the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, which addresses monitoring for certain emission units at major sources, thereby assuring that facility owners and operators conduct effective monitoring of their air pollution control equipment. In order to be subject to CAM, the following criteria must be met:

- The unit is subject to an emissions limitation or standard for the pollutant of concern
- An “active” control device is used to achieve compliance with the emission limit
- The emission unit’s pre-control potential to emit is greater than the applicable major source threshold

The CAM rule does not apply to facilities that are subject to Sections 111 (NSPS) or 112 (NESHAP) of the CAA issued after November 15, 1990; those sources subject to the acid rain program and emissions trading programs, or those facilities required to implement continuous monitoring in a Title V permit. The emissions units at Palomar that could potentially be subject to the CAM Rule are the turbines/duct burners, which are controlled by SCR for NO_x, an oxidation catalyst for CO control, and the cooling tower, which is controlled for PM₁₀ by drift eliminators. NO_x emissions from the combustion turbine units are subject to monitoring under the acid rain program required by Title IV of the CAA Amendments of 1990. The

5.2 Air Quality

facility will comply with the NO_x monitoring, recordkeeping and reporting requirements within 40 CFR 75, and thus is exempt from CAM for the combustion turbines for this pollutant. Palomar will be required by the Title V permit to monitor CO with a CEMS, so this pollutant is also exempt from CAM. In the case of the cooling towers, drift eliminators do not require continual adjustments, and hence would be classified as a “passive” rather than active control device. Therefore, this unit would not meet the applicability criteria of CAM.

Title V Operating Permit Program

In 1990, Congress passed the amendments to the Clean Air Act which in part required EPA to develop and promulgate an operating permit program that meets federal standards. The section of the 1990 CAA Amendments, for which the operating permit program requirement is established, is Title V. On July 21, 1992, EPA issued a regulation outlining the specific minimum requirements that states must meet in their operating permits program. This regulation is codified in 40 CFR Part 70 (Part 70). The function of the Title V permit and the Part 70 regulations are to assemble all applicable requirements for a source in a single operating permit.

State and local agencies were required to submit programs to EPA by November 15, 1993. EPA’s operating permits regulation requires states to develop comprehensive operating permit programs that cover “major” sources of air pollution. State programs that “substantially” met the regulatory requirements may be granted interim approval for up to two years (now extended) by EPA.

Palomar is subject to Title V because it meets the definition of a major source in both 40 CFR 70.2 and the SDAPCD Title V Permit Program (Regulation XIV). Compliance with 40 CFR 70 and the applicable subparts will be met with the submittal of a Title V application within one year after start of operation.

Title IV Acid Rain Provisions

Acid Rain provisions adopted as part of the 1990 Clean Air Act Amendments are primarily designed to control SO₂ and NO_x emissions that could form acid rain from fossil fuel fired combustion devices in the electricity generating industry. In an effort to accomplish this goal, an Acid Rain permitting program was established to mandate fuel based control, monitoring, recordkeeping, and reporting requirements. Requirements for the Acid Rain program are contained in SDAPCD Rule 1412.

The proposed facility combustion turbines are fossil fuel fired combustion devices used to generate electricity for sale and exceed the twenty-five (25) MW new Acid Rain unit exemption. Therefore, both proposed gas turbines meet the definition of an affected Phase II “utility unit” under the Acid Rain Deposition Control Program pursuant to Title IV of the CAA Amendments of 1990.

This will require the proposed facility to apply for a Title IV permit. An Acid Rain Permit application must include a compliance plan, the date that the unit will commence operation, and a deadline for monitoring certification. Regulatory provisions specify that the Acid Rain Permit application should be submitted twenty-four (24) months before the start of operation.

The Title IV permit will require that the facility evaluate allowances for emissions of SO₂ and conduct emissions monitoring for NO_x pursuant to the requirements in 40 CFR Parts 72, 73, and 75. Additional Acid Rain Permit controls will not be necessary to meet regulatory requirements, since the exclusive firing of natural gas will result in sufficiently reduced turbine emission levels.

A Title IV Acid Rain compliance plan will be submitted as required under 40 CFR 72. The plan will include the installation, proper operation and maintenance of continuous monitoring systems for NO_x (as the units will be fired with only natural gas, they are exempt from continuous monitoring of SO₂ and opacity). Depending on the monitoring technology available at the time of installation, the plan will cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan will also cite the specific form of records that will be maintained, their availability for inspection, and the length of time that they will be archived. The plan will cite that the acid rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and specific mechanism that will be used to keep current on rule applicability. The acid rain permit will be renewed prior to its expiration.

Allowances for SO₂ will be provided as required by 40 CFR 73 and NO_x CEMS will be installed and operated as required by 40 CFR Part 75.

5.2.7.2 State Regulations

Table 5.2-33 identifies the applicable state regulations and how Palomar project proposes to comply with these requirements.

California Health and Safety Code §41700. The Health and Safety Code prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public or which endanger the comfort, repose, health, or safety of the public, or that damage business or property. The Palomar Energy Project will satisfy these requirements by complying with SDAPCD Rule 51 requirements. Visible emissions and odors from his project are expected to be minimal. See also Section 7 which demonstrates insignificant air toxic impacts from the project. The administering agency is the SDAPCD.

California Clean Air Act, California Health and Safety Code § 42300 *et seq.* The California CAA establishes ambient air quality standards and classifies areas of the state depending on their attainment or non-attainment of these standards. The California Ambient Air Quality Standards are shown in Table 5.2-1. Local air pollution agencies are required to

5.2 Air Quality

implement measures to review and permit new and modified sources and to attain the ambient air quality standards.

The California Air Resources Board (ARB) provides oversight and policy direction to the local air pollution control agencies. The SDAPCD will be responsible for the review of the air permit application and enforcement of state air quality regulations.

Table 5.2-33 State Regulatory Requirements and Compliance

Regulation	Requirements	Compliance Demonstrated
California Health and Safety Code §41700	Prohibits discharge of air pollutants that cause injury, detriment, nuisance or annoyance to the public.	This requirement will be through compliance with SDAPCD Rule 51.
California Clean Air Act, California Health and Safety Code § 42300 <i>et seq.</i>	Enforces ambient air quality standards.	This requirement will be met through compliance with SDAPCD Rules which reflect the implementation plan.
California Health & Safety Code §§ 42301, 17 CCR § 70200	Requires permit to operate for facilities.	This requirement will be met by obtaining a Determination of Compliance from the SDAPCD for the project.
California Health and Safety Code § 44360-44366 - Air Toxic "Hot Spots" Information and Assessment.	Requires inventory of toxic emissions.	Air toxic emissions inventories will be submitted according to the schedule required by SDAPCD.

California Health & Safety Code §§ 42301, 17 CCR § 70200. The Health and Safety Code requires an air pollution control district to establish a permit system to "insure that (the use) for which the permit was issued shall not prevent or interfere with the attainment or maintenance of any applicable air quality standards". The SDAPCD will evaluate the project's compliance with all applicable rules and regulations. The SDAPCD will provide the evaluation as part of the Determination of Compliance (DOC) required under 20 CCR § 1744.5 (b) for the CEC's siting process. (The DOC is equivalent to the SDAPCD's Authority to Construct). Before the DOC is issued, the proposed project must comply with SDAPCD's rules and regulations. The administering agencies are the SDAPCD and the CEC.

California Health and Safety Code § 44360-44366 - Air Toxic "Hot Spots" Information and Assessment. Under California Health and Safety Code Sections 44360-44366, administered by SDAPCD, the Applicant will file the required air toxics emissions

information. This filing requirement applies after the start of operation. Assessments provided in Section 5.15 indicate that the Palomar Energy Project will have insignificant air toxic impacts. The administering agency is the SDAPCD.

5.2.7.3 Local Regulations

A list of the significant applicable or potentially applicable air quality rules and regulations and a brief summary of their requirements is provided in Table 5.2-34.

Table 5.2-34 Local Regulatory Requirements and Compliance

Regulation	Requirements	Compliance Demonstrated
Rule 20.1 New Source Review (NSR) General Provisions	Provides definitions as well as guidance for emission calculations.	Compliance demonstration not required.
Rule 20.3(d)(1) Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER)	Requires that BACT be installed on a pollutant specific basis if emissions exceed 10 lbs/day for each criteria pollutant (except CO for which PSD BACT threshold is 100 tpy). Also requires that LAER be installed on a pollutant specific basis if emissions exceed 50 tpy for NO _x or VOC.	This requirement is met as described in Section 5.2.2.
Rule 20.3(d)(2) Air Quality Impact Analysis (AQIA)	Requires that an AQIA be performed for air contaminants that exceed the trigger levels of Table 20.3-1 of the SDAPCD's Rules.	This requirement is met as described in Section 5.2.3.
Rule 20.3(d)(3) Prevention of Significant Deterioration (PSD)	Requires that a PSD evaluation be performed for all contaminants which exceed PSD major source trigger levels.	This requirement is met as described in Sections 5.2.2 and 5.2.3.
Rule 20.3(d)(e)(ii) Notification Requirements	Requires that written notification be provided to the Federal Land Manager of intent to file an application for an ATC, PTO, or DOC, at least 30 days prior to application submittal.	This requirement is met with the written notification for the project submitted to the Federal Land Manager on October 10, 2001

Table 5.2-34 Local Regulatory Requirements and Compliance (cont'd)

Requirements	Requirements	Compliance Demonstrated
Rule 20.3(d)(4) Public Notice and Comment	Requires that SDAPCD publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County, as well as send notices to the EPA and CARB.	This requirement is met by the SDAPCD.
Rule 20.3(d)(5) Emission Offsets	Requires that emissions of any federal non-attainment criteria pollutant or its precursors, that exceed major source thresholds, be offset with actual emission reductions.	Sufficient emission reduction credits will be provided to offset the NO _x emissions from the facility.
Rule 20.3(d)(8) LAER and Federal Offset Requirements	Requires that the NO _x and VOC emission increases from a new, modified, relocated or replacement emission unit or project which increases constitute a new major source or major modification of a major stationary source shall be offset at a ratio of 1.2 to 1.0, on a pollutant specific basis. Interpollutant offsets may be used provided they meet the requirements of Subsection (d)(5)(vi).	Offset requirements will be met as discussed above. LAER requirements are met as described in Section 5.2.2.
Rule 20.3(e)(1) Compliance Certification	Requires that the Applicant for the project certify that they are in compliance at all facilities owned by the Applicant in California.	Neither Palomar Energy, LLC nor Sempra Energy Resources currently own any operating facilities within California.
Rule 20.3(e)(2) Alternatives Analysis	Requires that an Applicant for a new major stationary source that is required to satisfy the LAER requirements of Rule 20.3(d)(1) or the offset requirements of Rule 20.3(d)(5) conduct an alternatives analysis.	Section 3 of the AFC provides an alternatives analysis for Palomar, including assessment of environmental issues.
Rule 20.5 Power Plants	Requires that the SDAPCD submit Preliminary and Final Determination of Compliance reports to the CEC, which shall be equivalent to an evaluation for a SDAPCD Authority to Construct.	This requirement is met by the SDAPCD.

Table 5.2-34 Local Regulatory Requirements and Compliance (cont'd)

Requirements	Requirements	Compliance Demonstrated
Rule 50 Visible Emissions	Prohibits air contaminant emissions into the atmosphere darker than Ringelmann Number 1 (20 percent opacity) for more than an aggregate of three minutes in any consecutive sixty minute time period.	Only natural gas fired equipment will be used at this site.
Rule 51 Nuisance	Prohibits the discharge of air contaminants that cause or have a tendency to cause injury, nuisance, annoyance to people and/or the public or damage to any business or property.	During operation, fugitive dust and odors are expected to be minimal.
Rule 53 Specific Air Contaminants	Limits emissions of sulfur compounds (calculated as SO ₂) to less than or equal to 0.05 percent, by volume, on a dry basis; also limits particulate matter emissions from gaseous fuel combustion to less than or equal to 0.1 grains per dry standard cubic foot of exhaust calculated at 12 percent CO ₂ .	Only low sulfur (0.75gr/100 scf) natural gas will be used.
Rule 68 Fuel-Burning Equipment – Oxides of Nitrogen	Limits NO _x emissions from any fuel burning equipment to less than 125 ppmv calculated as NO ₂ at 3% oxygen on a dry basis.	Since the equipment is subject to the requirements of Section (d) of Rule 69.3.1, the equipment is exempt from this rule. However, NO _x will be limited to 2 ppm based on LAER.
Rule 69.3 Stationary Gas Turbines – Reasonably Available Control Technology	Limits NO _x emissions from gas turbines greater than 0.3 MW to 42 ppm at 15 percent oxygen when fired on natural gas; also specifies monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by this rule and excluded from compliance with these limits.	Gas turbines will be limited to 2 ppm NO _x based on LAER.

Table 5.2-34 Local Regulatory Requirements and Compliance (cont'd)

Requirements	Requirements	Compliance Demonstrated
Rule 69.3.1 Stationary Gas Turbines – Best Available Retrofit Control Technology	Limits NO _x emissions from gas turbines greater than 10 MW to 15x(E/25) ppm when operating uncontrolled and 9x (E/25) ppm at 15 percent O ₂ when operating with controls and averaged over a 1-hour period. E is the thermal efficiency of the unit. The rule also specifies monitoring and recordkeeping requirements. Startups, shutdowns, and fuel changes are defined by this rule and excluded from compliance with these limits.	Gas turbines will be limited to 2 ppm NO _x based on LAER.
Regulation X Standards of Performance for New Stationary Sources (NSPS)	This Regulation adopts by reference federal NSPS requirements. The requirements are listed in Appendix C to the Regulations.	The NSPS that are applicable to this project are described in Table 5.2-31.
Regulation XI National Emission Standards for Hazardous Air Pollutants (NESHAP)	This Regulation adopts federal NESHAP requirements by reference.	Palomar will comply with future MACT standards if they are applicable.
Rule 1200 Toxic Air Contaminants, New Source Review	Requires that a Health Risk Assessment (HRA) be performed if the emissions of toxic air contaminants will increase. A detailed HRA is necessary if toxic emissions exceed SDAPCD de minimus (minimum threshold) levels. Toxics Best Available Control Technology (TBACT) must be installed if the HRA shows a cancer risk greater than one in a million. At no time shall the cancer risk exceed ten in a million.	This requirement is met as described in Section 5.15. An HRA was performed and cancer risks are less than one per million during power plant operation.
Rule 1401 Title V	Outlines requirements for facilities	This requirement will be

Table 5.2-34 Local Regulatory Requirements and Compliance (cont'd)

Requirements	Requirements	Compliance Demonstrated
Operating Permits General Provisions	subject to Title V requirements.	met by submitting a Title V permit application.
Rule 1412 Federal Acid Rain Program Requirements	The provisions of 40 CFR Part 72 in effect on January 18, 1994 are adopted by reference for the purposes of implementing an acid rain program that meets the requirements of Title IV of the federal Clean Air Act.	This requirement will be met by submitting a Phase II acid rain application.

New Source Review/Permits

The SDAPCD has been delegated authority for New Source Review and PSD rule development and enforcement by the EPA. There are three basic permitting elements for major stationary source projects. The first is a pollutant-specific technology requirement consisting of the Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). BACT/LAER applies to any new or modified stationary source that emits or has the potential to emit above specified threshold quantities. This requirement is addressed in Section 5.2.2. The second basic element for permitting is an air quality impact and air quality related values assessment; these requirements are addressed in Section 5.2.3. The third major element is the provision of offsets. This requirement is addressed in this Section under Rule 20.3(d)(5).

The following SDACPD rules address the New Source Review requirements of Major Stationary Sources including PSD requirements.

The subsection Rule 20.3(d)(1) Best Available Control Technology/Lowest Achievable Emission Rate requires that BACT be installed on a pollutant-specific basis if emissions exceed 10 lbs/day for each criteria pollutant (except for CO, for which the PSD BACT threshold is 100 tons/yr). This subsection also requires that LAER be installed on a pollutant-specific basis if the emissions exceed 50 tons/yr for NO_x or VOC emissions. Because the SDAPCD is in attainment status for the National ambient air quality standards for CO, SO_x, and PM₁₀, LAER does not apply to these particular pollutants (SDAPCD Rule 20.3(d)(1)(v)). However, BACT does apply for NO_x, VOC, SO_x, and PM₁₀ since the SDAPCD is in non-attainment for the state ambient air quality standards for ozone (for which NO_x and VOC emissions are precursors), and PM₁₀ (SDAPCD Rule 20.3(d)(1)(i)). Additionally BACT applies for CO, and PM₁₀ if they trigger PSD major source thresholds of 100 tons/yr (SDAPCD Rule 20.3(d)(1)(vi)).

5.2 Air Quality

The subsection Rule 20.3(d)(2) Air Quality Impact Analysis (AQIA) requires that an AQIA be performed for air contaminants that exceed the trigger levels of Table 20.3-1 of the SDAPCD's Rules and Regulations. An AQIA for the Palomar Energy Project is triggered for NO_x, CO, and PM₁₀.

The subsection Rule 20.3(d)(3) Prevention of Significant Deterioration (PSD) requires that a PSD evaluation be performed for all contaminants that exceed PSD major source trigger levels. These evaluations are addressed in this application.

The subsection Rule 20.3(d)(e)(ii) Notification Requirements requires that written notification be provided to the Federal Land Manager of intent to file an application for an ATC, PTO, or DOC, at least 30 days prior to application submittal. This requirements is met by the written notification submitted to the Federal Land Manager on October 10, 2001.

The subsection Rule 20.3(d)(4) Public Notice and Comment requires the SDAPCD to publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County as well as send notices to the EPA and ARB. The SDAPCD must allow at least 30 days for public comment and consider all comments submitted. The SDAPCD must also make all information regarding the evaluation available for public inspection.

The subsection Rule 20.3(d)(5) Emission Offsets requires that emissions of any federal non-attainment criteria pollutant or its precursors that exceed major source thresholds be offset with actual emission reductions. The subsection Rule 20.3(d)(8) LAER and Offset Provisions Requirements contains additional requirements for major sources in a federal non-attainment area. Of the six criteria pollutants, ozone, NO₂, CO, SO₂, PM₁₀, and lead, the SDAPCD is a federal non-attainment area only for ozone. Therefore, offsets are potentially only required for NO_x and VOC emissions, as ozone precursors. However, VOC emissions are expected to be below major source levels (50 tpy). Therefore, offsets are required only for NO_x emissions.

Offsets may be actual emission reductions, stationary source Class A emission reduction credits (ERCs) issued under SDAPCD Rules 26.0-26.10, or mobile source emission reduction credits (MERCs) issued under SDAPCD Rule 27. The applicant is required [Rule 20.1(d)(5)] to have the actual emission reductions in place and/or surrender emission reduction credits (ERCs or MERCs) before initial startup.

Palomar will offset NO_x emissions with NO_x ERCs and/or with an interpollutant trade of VOC ERCs as allowed by SDAPCD Rule 20.3(d)(8). NO_x ERC will be provided at a ratio of 1.2 to 1.0. Alternatively, VOC ERC will be provided at an additional ratio of 2.0 to 1 (or a total of 2.4 tons of VOC ERCs to 1.0 ton of NO_x emissions) as specified by the rule. VOC emissions are below the level that require offsets under SDAPCD rule; therefore VOC offsets are not required. Palomar is not seeking to waive the AQIA requirement for PM₁₀ and has demonstrated that the proposed project is not expected to cause or contribute to a violation of the California AAQS (Rule 20.3(d)(2)(i)). Therefore, PM₁₀ offsets are not required. Since the area is attainment for CO and SO₂, offsets for these pollutants are not required.

The subsection Rule 20.3(e)(1) Compliance Certification requires that the applicant certify that all major stationary sources owned or operated by the applicant are in compliance, or on an approved schedule for compliance, with all applicable emission limitations and standards under the federal Clean Air Act.

This subsection Rule 20.3(e)(2) Alternative Siting and Alternatives Analysis requires that the Applicant conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques of the proposed source. This analysis must demonstrate that the benefits of the proposed source outweigh the environmental and social costs imposed as a result of its location or construction. An analysis that meets these requirements is provided in Section 3 of this Application for Certification.

Power Plants

Rule 20.5 requires that the SDAPCD submit Preliminary and Final Determination of Compliance reports to the CEC that shall be equivalent to an evaluation for a SDAPCD Authority to Construct.

Prohibitory Rules

The SDAPCD has a number of prohibitory rules. Following is a description of the applicable and more significant regulations.

Rule 50 Visible Emissions limits air contaminant emissions into the atmosphere of shade darker than Ringlemann Number 1 (20% opacity) for more than an aggregate of three minutes in any consecutive sixty minute time period.

Rule 51 Nuisance prohibits the discharge of air contaminants that cause or have a tendency to cause injury, nuisance, annoyance to people and/or the public or damage to any business or property.

Rule 53 Specific Air Contaminants limits emissions of sulfur compounds (calculated as SO₂) to less than or equal to 0.5%, by volume, on a dry basis. This rule also limits particulate matter emissions from gaseous fuel combustion to less than or equal to 0.1 grains per dry standard cubic foot of exhaust calculated at 12% CO₂.

Rule 68 Oxides of Nitrogen from Fuel Burning Equipment limits NO_x emissions from any fuel burning equipment to less than 125 ppmv calculated as NO₂ at 3% oxygen on a dry basis. Since this equipment is subject to the requirements of Section (d) of Rule 69.3.1, the equipment is exempt from this rule.

Rule 69.3 Stationary Gas Turbines - Reasonably Available Control Technology limits NO_x emissions from gas turbines greater than 0.3 MW to 42 ppm at 15% oxygen when fired on natural gas. The rule also specifies specific monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits.

5.2 Air Quality

Rule 69.3.1 Stationary Gas Turbines - Best Available Retrofit Control Technology limits NO_x emissions from gas turbines greater than 10 MW to 15x(E/25) ppm when operating uncontrolled and 9x(E/25) ppm at 15% oxygen when operating with controls and averaged over a 1-hour period. E is the thermal efficiency of the unit. The rule also specifies monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits.

NSPS and NESHAP

Regulation X adopts by reference federal NSPS requirements. The requirements are listed in Appendix C to the Regulations. Compliance with applicable NSPS requirements is addressed in Section 5.2.7.1.

Regulation XI adopts federal NESHAP requirements. Compliance with the only identified NESHAP requirement – Subpart M for Asbestos is discussed in Section 5.2.7.1.

Toxic Air Contaminants

Rule 1200 New Source Review for Toxic Air Contaminants requires that a Health Risk Assessment (HRA) be performed if the emissions of toxic air contaminants will increase. A detailed HRA is necessary if toxic emissions exceed SDAPCD de minimis levels. Toxic Best Available Control Technology (T-BACT) must be installed if the HRA shows a cancer risk greater than one in a million. At no time shall the cancer risk exceed ten in a million. An analysis has been performed (see Section 5.15) and maximum due to operation of the Palomar facility cancer risk is expected to be less than one in a million.

Title V Operating Permits and Title IV Acid Rain Requirements

Title V of the 1990 Clean Air Act Amendments requires states to implement and administer an operating permits program consistent with the provisions of 40 CFR Part 70. SDAPCD has been delegated interim approval authority to administer the federal Title V operating permit program under Regulation XIV of the Air Pollution Control Regulations. The only remaining issue requiring resolution prior to final approval of the SDAPCD's Title V program is the statewide exemption of agricultural sources.

Regulation XIV provides provisions for Title V operating permits, including the requirements of the Title IV Acid Rain program. Specifically, Rule 1401 are the General Provisions. Rule 1412 addresses the requirements of the Acid Rain program.

Title V and Title IV applications for the Palomar Energy Project will be submitted to SDAPCD in a timely manner. A Title IV application must be submitted 24 months prior to the start of operation of the planned facility. A Title V permit application must be submitted within 12 months after start up (i.e., commencing commercial operation) per Rule 1414(d).

5.2.8 Involved Agencies and Agency Contacts

Contacts for air quality agencies having authority over construction and operation of the Palomar Energy Project are presented in Table 5.2-35.

Table 5.2-35 Involved Agencies and Agency Contacts

Agency/Address	Contact/Telephone	Permits/Reason for Involvement
San Diego Air Pollution Control District 9150 Chesapeake Drive San Diego, California 92123-1096	Mike Lake (858) 650-4700	Determination of Compliance Permit to Operate PSD Permit ¹
EPA Region IX 75 Hawthorne Street San Francisco, CA 94105	Geraldo Rios (415) 947-8021	Title V Operating Permit ² Title IV (Acid Rain) ²

1 PSD and Title V Operating Permit issued by SDAPCD, with oversight from EPA Region IX

2 The requirements of the Acid Rain program will be incorporated into the Title V Operating Permit

5.2.9 Permits Required and Permit Schedule

Permits required and permit schedule for matters dealing with air quality for the Palomar Energy Project are provided in Table 5.2-36.

Table 5.2-36 Permits Required and Permit Schedule

Permit/Approval Required	Schedule
Determination of Compliance	Prior to construction.
Prevention of Significant Deterioration	Prior to construction.
Title IV (Acid Rain)	Submit 24 months prior to operation.
Title V Operating Permit	Submit within 12 months of initial operation.

5.2.10 References

California Air Pollution Control Officers Association (CAPCOA). 1993. Air Toxics "Hot Spots" Program: *Revised 1992 Risk Assessment Guidelines*.

5.2 Air Quality

- California Air Resources Board (ARB). 2001. California Air Toxic Emission Factor (CATEF, <http://www.arb.ca.gov/emisinv/catef/catef.htm>). Updated with AB2588 Phase II toxic emission factors in January 2001.
- California Air Resources Board. September 1999. Guidance for Power Plant Siting and Best Available Control Technology.
- Federal Land Managers' Air Quality Related Values Workgroup (FLAG). December 2000. Phase I Report. U.S. Forest Service, U.S. National Park Service, U.S. Fish and Wildlife Service.
- Federal Land Managers' Air Quality Related Values Workgroup (FLAG). 2001. Guidance on Nitrogen Deposition Analysis Thresholds. 2001.
- Federal Register (FR21506). 2000. Requirements for Preparation, Adoption, and Submittal of State Implementation Plans (Guideline on Air Quality Models); Proposed Rule. Vol. 65, No. 78. April 21, 2000.
- Interagency Workgroup on Air Quality Modeling (IWAQM). December 1998. Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. EPA-454/R-98-019.
- McCorison, M. 2001. Personal communication with Federal Land Manager, October 31, 2001.
- National Climatic Data Center. 1993. Local Climatological Data – San Diego, California. ISSN 0198-0971.
- Office of Environmental Health Hazard Assessment (OEHHA). 2001. Consolidated Table of OEHHA/ARB Approved Risk Assessment Health Values. Updated
- SDAPCD. 2001. Personal Communication between Patrick McKean and Ralph DiSiena.
- Stone & Webster. 2000. Independent Technical Review SCONOX™ Technology and Design Review (J.O. 08999).
- U.S. EPA. 1992. “Workbook for Plume Visual Impact Screening and Analysis”. EPA-450/4-88-015. Office of Air Planning Quality and Standards, Research Triangle Park, NC.
- U.S. Forest Service (R. D. Doty, R. W. Fisher, D. L. Peterson, D. L. Schmoldt, and J. M. Eilers). 1992. Guidelines For Evaluating Air Pollution Impacts on Class I Areas in California.